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July 8, 2016

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 160105-EI – Petition for approval of 2016-2018 storm hardening plan, pursuant to Rule 25-6.0342, F.A.C., by Tampa Electric Company

Dear Ms. Stauffer:

Attached for filing in the above docket is Tampa Electric Company's Responses to Staff's First Data Request (Nos. 1-19) dated June 8, 2016.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

cc: Penelope D. Buys (w/attachment)

1. Referring to page 9, Initiative 1: Four-year Vegetation Management, please explain:

a) The flexibility that the plan allows to change circuit prioritization.

b) TECO's reliability based methodology.

A. a. Tampa Electric's Vegetation Management Plan ("VMP") allows for flexibility to support changes in circuit prioritization. These prioritization changes are necessary to support the changes that occur due to growth, reconfiguration or equipment additions to the company's distribution system as well as due to demands of customers. To support these changes requires the VMP to allow for a sensible level of flexibility. Tampa Electric's VMP is largely based on the analysis of the third party software application, prior to changing circuit prioritization factors such as the following are considered:

- Geography
- Soil Type
- Circuit Breaker
- Work Type
- Accessibility

In addition to considering these factors, Tampa Electric's Line Clearance arborists are continually monitoring system changes, operational needs, and resource availability to ensure the goals of the company and demands of the customers are met.

b. Tampa Electric's reliability based methodology is included in the Tree Trimming Cycle Analysis that was published on January 6, 2012. A complete copy of the report starts on the next page:

STRATEGIES FOR COMPLEX ORGANIZATIONS

Tampa Electric

Tree Trimming Cycle Analysis

January 06, 2012

Prepared For:

TECO
TAMPA ELECTRIC

Prepared By:

davies consulting inc.

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Executive Summary

In 2007, Tampa Electric utilized Davies Consulting (DCI) to conduct a structured approach in the evaluation of alternative vegetation management (VM) programs with the objective of ultimately developing a VM strategy that would enable the company to meet its reliability performance targets, financial requirements, as well as the commitments made to the Florida Public Service Commission (PSC). In 2011, Tampa Electric retained DCI to update the study in order to re-assess different VM strategies and determine whether the company's existing VM program continues to meet current performance objectives and PSC requirements. Specifically, the objective of the study was to compare costs and benefits of a three-year cycle to a four-year cycle.

To meet the objective, Tampa Electric retained the services of DCI to implement its Tree Trimming Model (TTM™), a data-driven tool for optimizing VM activities from a cost-reliability standpoint. The project involved intensive data gathering and processing. Data collection focused on three primary sources: the Geographic Information System (GIS) for circuit data such as overhead length, voltage, and substation; the Distribution Outage Database (DOD) for outage data from January 2002 to June 2011; and historical trimming and cost data. The trim history was reconciled with Tampa Electric personnel's knowledge of the system in order to establish average trimming costs for year 2010. Using the information gathered and knowledge of the system, all Tampa Electric circuits were grouped into performance and cost curves.

The analysis described in this report focused on evaluating two scenarios. The first scenario is based on the current Tampa Electric VM program and includes trimming approximately one-third of overhead miles a year in each service area, equal to a three-year trimming cycle. The alternative scenario represents a four-year cycle that is based on trimming approximately one-quarter of overhead miles a year in each service area. In addition to evaluating the costs of each scenario and resulting reliability performance, TTM was also used to assess the overall system costs (including normal, storm restoration, and corrective maintenance costs) associated with the two scenarios.

When compared, the four-year trim cycle costs approximately $12.9 million less than the three-year trim cycle over a ten-year period and results in a predicted average tree-related SAIDI of 23.62 minutes per year. The estimated average tree-related SAIDI associated with the three-year trim cycle is approximately 2.67 minutes lower. The net present value (NPV) of the total VM program cost (including normal, storm restoration, and corrective maintenance costs) associated with the four-year cycle is $3.1 million less than the NPV of the total VM program costs associated with the three-year cycle.

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1. Introduction

Tampa Electric requested DCI to conduct a structured approach in the evaluation of alternative VM programs. The ultimate objective was to develop a VM strategy that would meet the company's reliability objectives, financial requirements, and commitments made to the PSC.

DCI utilized its TTM, a data-driven tool for optimizing spending on trim activities for reliability. The initial implementation of the TTM was carried out in 2007 and involved two phases. The first, referred to here as the "core TTM analysis," was geared toward an evaluation of the impact of tree-trimming spending on day-to-day reliability performance. The second phase, referred to as the "storm scenario analysis" explored the storm restoration cost implications of the different strategies.

Since this initial implementation, Tampa Electric staff has maintained the model and used the analysis in order to support its prioritization of circuits for its VM program each year. In addition, with support from DCI, every two years since the initial implementation, Tampa Electric undertook a broader effort to update the assumptions and analysis based on the most recent outage and trim data. This report summarizes the results of the most recent TTM update which was completed in late 2011.

Tampa Electric currently trims the entire circuit starting from the breaker as a part of its VM program. In the initial implementation of the TTM, the company evaluated the costs and benefits associated with trimming backbone and lateral sections of the circuits on a different cycle. However, in the latest analysis, and after careful consideration, it was decided that splitting circuits into backbone and lateral sections for VM was not practical nor did it align with the company's operating philosophy. Some specific challenges with backbone/lateral split include:

- Most of the lateral sections of the circuits are not currently fused, minimizing the reliability benefit of trimming backbone sections on a more frequent cycle;
- Historical data was not tracked separately for backbone and laterals in order to make sound assumptions related to costs and reliability benefits for the different sections; and,
- Demarcation of lateral vs. backbone sections in the field and on maps is not clearly established, which would make it difficult to implement the program in the field.

The purpose of this report is to serve as a reference for the data collection and processing involved in conducting a TTM evaluation, summarize the results from the latest analysis that was performed, and provide sound judgment from the results of the analysis.

This report is divided into the following sections:

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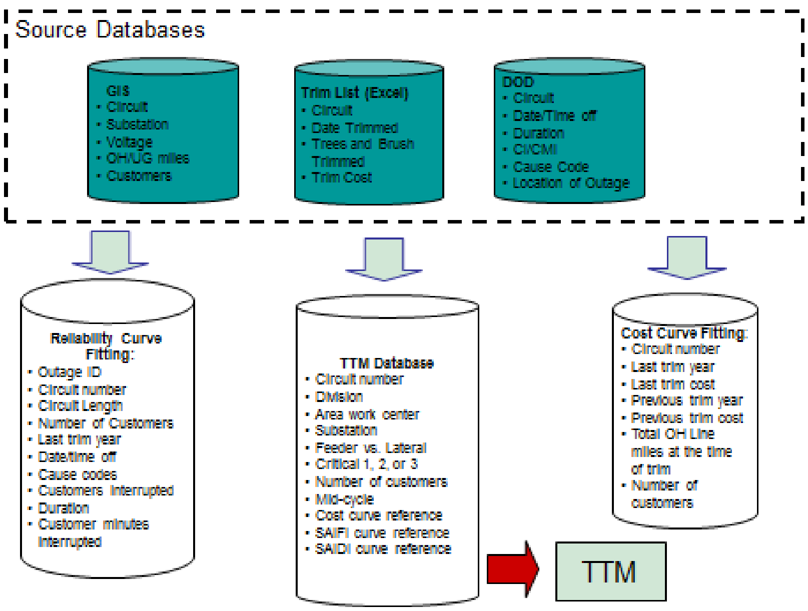
- Section 2 describes the sources of data and some basic statistics derived from them;
- Section 3 discusses how the data was processed and how the key assumptions were made in order to generate cost and performance curves;
- Section 4 describes the core TTM scenario analysis, focusing on the impact of the two trimming programs on spending and day-to-day reliability; and,
- Section 5 describes the storm scenario analysis, where the impact of tree trimming strategies on the budget and reliability is supplemented by an analysis of storm restoration costs.

2. Data Sources and Characteristics

The TTM analysis typically requires three principal data sources:

- A complete inventory of the overhead circuits in the system, including circuit characteristics such as customer count, overhead mileage, and geographic coordinates;
- The outage database or databases; and,
- A history of trimming activity, preferably including start and end dates, costs, and covering multiple trims for each circuit.

Figure 1 - TTM Data Sources and Data Flow



2.1. Circuit List

2.1.1. Data Sources

A comprehensive list of circuits was obtained from Tampa Electric's GIS, which contained a total of 754 circuits.

Not all circuits and mileage were of interest, as TTM is only relevant to the overhead portion of circuits for which trimming is a regular concern. Ultimately, 701 "trimmable" circuits were included in the analysis, representing some 6,330 miles of overhead circuit length.

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Circuits were also assigned geographic point designations by taking the average latitude and longitude of all transformers on each circuit, which was also extracted from the GIS. This would later enable plotting of circuits on an area map for easier visualization of the recommended trimming cycles.

2.2. Performance Data

2.2.1. Data Sources

Circuit reliability performance data was gathered from Tampa Electric's DOD. The analysis included outages from January 1, 2002 through June 30, 2011, thus accommodating at least nine full calendar years. Of particular interest were outages with the tree-related cause codes found in Table 1 below. The table indicates the number of events associated with each cause code, as well as the total customer interruptions (CI) and customer minutes of interruption (CMI).

Table 1: Tree-Related Cause Codes (January 1, 2002 – June 30, 2011)

Cause Code	Events	CI	CMI
Non Preventable	1,964	164,718	17,091,713
Other Weather	281	28,219	8,493,216
Preventable	2,244	144,630	14,462,951
Tree\Blew into Line	810	59,365	17,487,512
Tree\Fell into Line (Non Prev.)	3,879	411,706	32,519,616
Tree\Fell into Line (Prev.)	3,039	277,067	22,766,690
Tree\Grew into Line	4,362	204,751	16,452,870
Tree\Vines	2,723	23,812	2,386,402
Trees (Other)	310	11,864	1,262,496
Vines	1,062	9,513	1,038,094
Wind	175	58,908	24,005,988
Incorporated Unknown	4,250	147,211	8,828,646
Incorporated Weather	1,702	204,466	50,262,670
Grand Total	26,801	1,746,230	217,058,864

Tampa Electric also incorporated a portion of CIs and CMIs from outages with "Unknown" and "Weather" cause codes. From experience, DCI has found with other utilities that a significant portion of such catch-all causes is, in fact, tree-related. Therefore, after conducting an internal analysis of trends in outage counts for these cause codes in relation to explicit tree cause codes, Tampa Electric determined that 25 percent was a reasonable proportion to include in the analysis.

Finally, certain outages were excluded from this analysis irrespective of the cause code. These included those adjustments specified and allowed in accordance with Rule 25-6.0455, Florida Administrative Code.

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2.3. Trim Data

2.3.1. Data Sources

Tampa Electric records and maintains trim history that includes the following types of data:

- Circuit number;
- Trim completion date; and,
- Cost to trim the entire circuit.

The trim data was paired down to the outage data with the circuit number being the link between the two data sources. For analysis purpose the circuit number and trim completion date (year and month of trim) of each circuit trim were incorporated in the analysis.

Many circuits had no completion date but were "in progress" meaning they were being trimmed. Although some outages may have occurred after the start of the trim, the previous trim completion date was used in the analysis of that particular circuit.

2.3.2. Trim Cost Estimates

Tampa Electric provided DCI with 2010 trim cost estimates in order to validate or update cost curves for each of the service areas. This resulted in minor adjustments to the curves which will be discussed in Subsection 3.2.

2.3.3. Last Trim Dates

An important data element included in TTM is the last trim date of each circuit. This allows the model to determine the current state of the circuit and the resulting reliability deterioration and trim cost escalation. All circuits had an identified last trim date. Also, 13 new circuits were installed after 2009; therefore, the assumption was made to use each new circuit's installation date as its last trim date.

3. Data Processing and Grouping

The TTM analysis process requires both performance-based curves and cost-based curves be developed based on the available data. This section describes the process DCI applied at Tampa Electric to accomplish this task.

3.1. Reliability Performance Curve Development

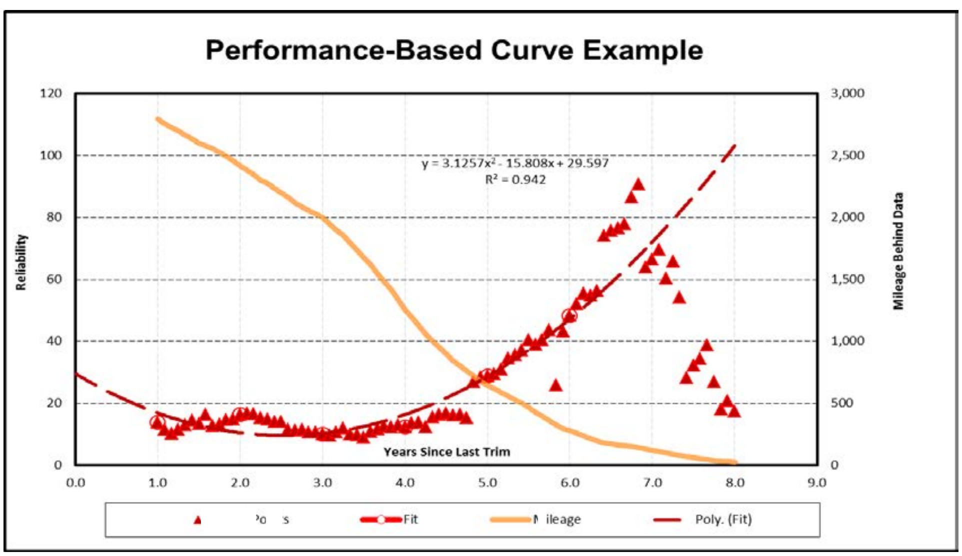
3.1.1. Generating Data Points

Performance data points were derived using historical outage data, trim data, and circuit length data. Every outage was expressed as a number of CI or CMI per circuit mile, and was plotted relative to the most recent time it was trimmed. Values for 12 consecutive individual months were rolled up to create year-based values, and these were plotted in MS Excel so that a curve could be fit to them.

A number of conditions had to be satisfied in order to ensure that the data points were correct:

- Outage data was omitted in the months when a circuit was being trimmed.
- Outages were associated only to the most recent trim.
- Figure 2 below reflects the mileage into which the 12-month roll-up of CI or CMI is divided and represents the total mileage of the system or group of circuits. This ensures that in a situation where several circuits do not have any outages in a particular 12-month roll-up, those circuits were not disregarded, but rather served to appropriately pull the curve downward as part of the averaging process. This provided assurance that the resulting curves were representative of the overall CI or CMI per mile of circuits in the group and not just the CI or CMI per mile on circuits that happened to have outages.

Figure 2 - Sample Performance Curve



3.1.2. Choice of performance parameter

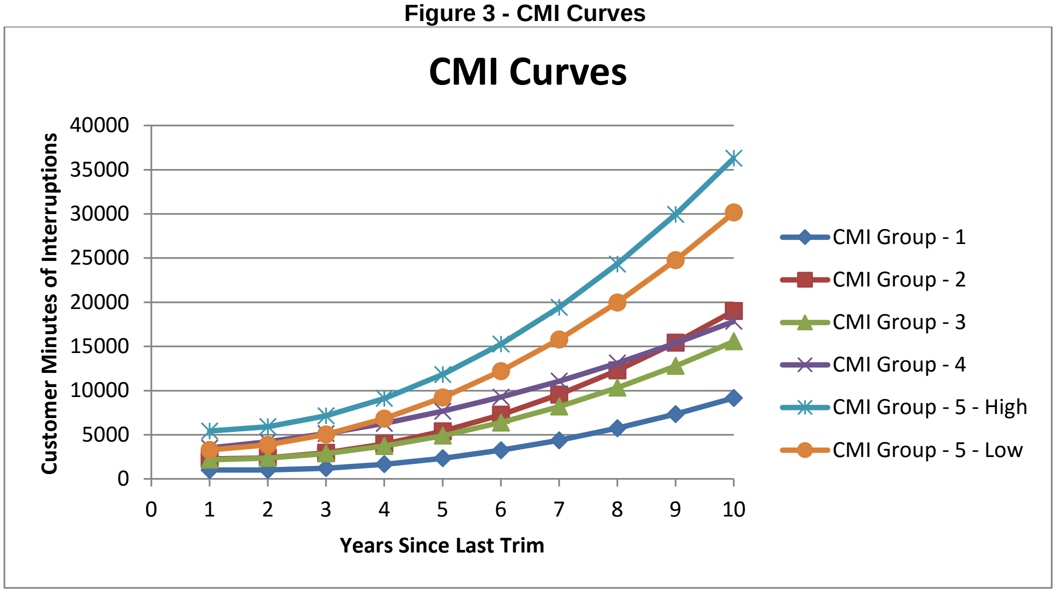
SAIDI has been the reliability measure of greatest interest to Tampa Electric, and as a result, significant attention was dedicated to developing CMI curves. Eventually, scenarios were run with SAIDI as the optimized parameter. However, CI curves were also developed as they were necessary in the TTM storm analysis module.

3.1.3. Creating Circuit Performance Groups

Circuits were grouped according to historical performance, initially by deciles (tenths) of total tree-related CMI per mile (including approximately 25 percent of Unknown and Weather CMI) from 2002 to 2006. The same circuit grouping was kept in subsequent updates to the TTM assumptions since the CMI/mile characteristics of the circuits did not vary significantly to allow for big circuit movement across groups. The new circuits installed after 2009 were assigned to the appropriate group based on their CMI/mile values if they witnessed outage events or to the CI and CMI Group 1 if they did not encounter any outage events thus far.

A curve similar to that shown in Figure 2 was developed for each of the CMI groups, resulting in a total of six curves, which are shown in Figure 3 below. These curves provided the critical input required to compute the projected reliability associated with trimming each circuit. Eventually, the computed reliability values were used as the denominator to determine the cost-effectiveness score for circuits, which then served as the basis for their prioritization.

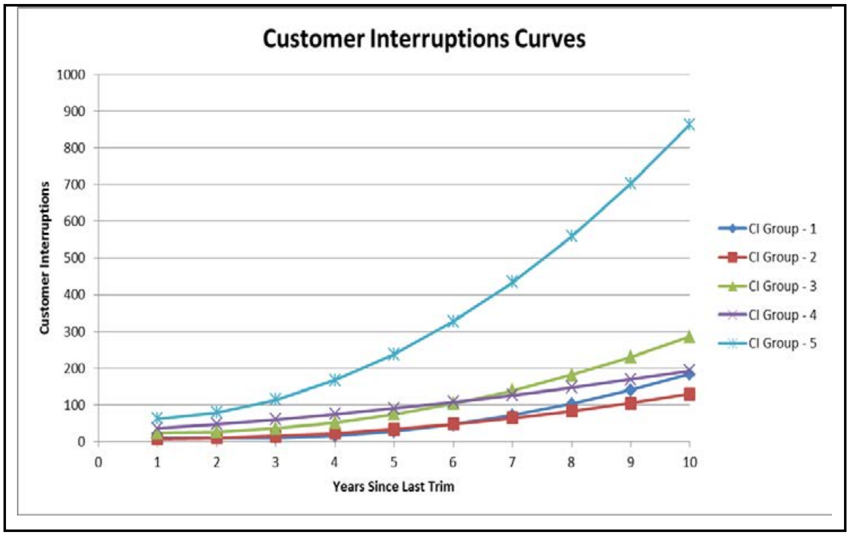
Figure 3 - CMI Curves



When viewed geographically, it should be observed that each of the company's seven service areas has a mixture of circuits belonging to different CMI groups. This was important to ensure that the trim optimization would not be geographically biased, but rather that trim resources would be equitably distributed across service areas according to potential reliability gains.

Although optimization was driven by the CMI curves, it was also necessary to develop CI curves in order for the model to generate CI estimates for each scenario. As will be discussed in Subsection 5.1.2, annual non-storm restoration costs were driven by CI rather than CMI. The CI circuit grouping was slightly different from the CMI groups. The resulting CI curves are shown in Figure 4.

Figure 4 - CI Curves



3.2. Cost Curve Development

Cost curves were the second factor in calculating the cost/benefit score of each circuit in TTM.

The shape of the cost curves were based on the Economic Impacts of Deferring Electric Utility Tree Maintenance study by ECI[1] that quantified the percentage increase in the eventual cost of trimming a circuit for each year that it is left untrimmed beyond the recommended clearance cycle. The findings of the ECI study are summarized in Figure 5 below. For instance, if the clearance cycle is three years, then waiting four years between trims will increase the cost per mile by 20 percent. Delaying trimming by another year will further inflate costs to 40 percent of the base cost and further increase it for subsequent years.

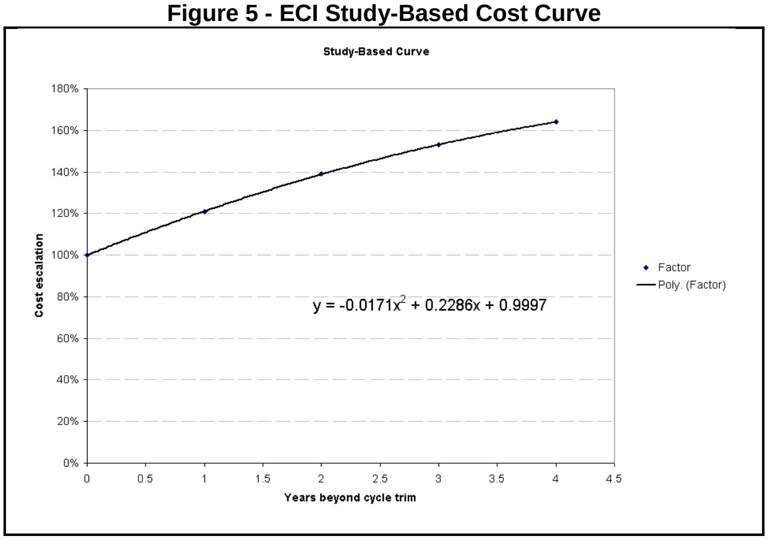
The ECI study only considered annual trimming cost increases between the recommended clearance cycle and up to a four-year delay. In generating a

[1] Browning, D. Mark, 2003, Deferred Tree Maintenance, Environmental Consultants Incorporated (ECI)

comprehensive cost curve that goes from one year since last trim onward, DCI supplemented the percentages from the ECI study with two assumptions:

- Cost reduction from annual trimming – the percentage reduction from the clearance trim that will be achieved if the circuit was trimmed every year; and,
- Escalation – annual percentage increase in cost to be applied from the fourth year after the clearance cycle onward.

Figure 5 - ECI Study-Based Cost Curve



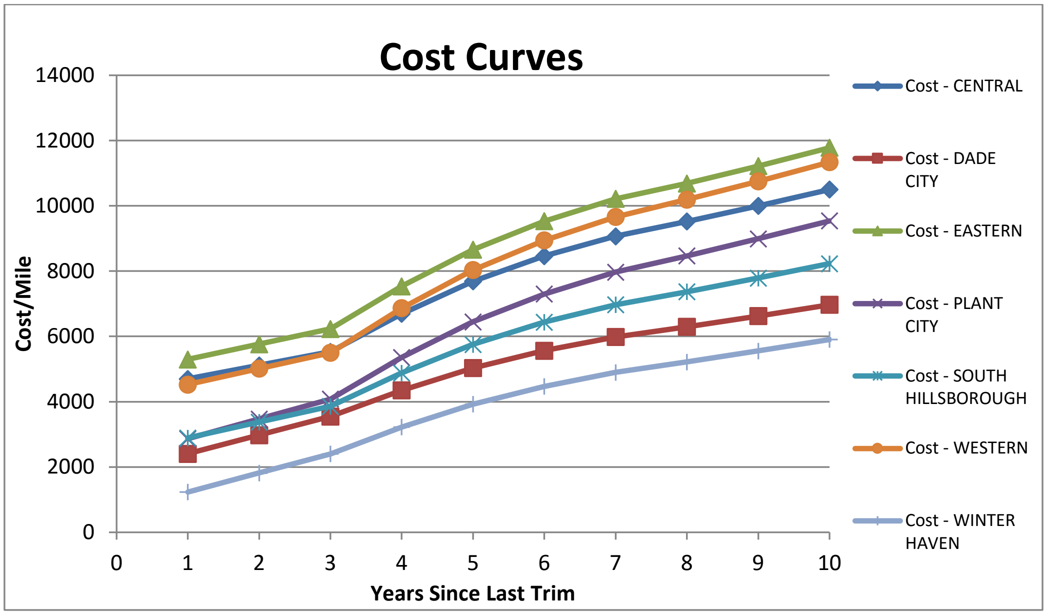
The following section describes how such a cost curve methodology was applied to each of Tampa Electric's seven service areas.

3.2.1. Applying ECI study parameters and 2010 cost

Tampa Electric's cost-per-mile estimates were derived using 2010 data. However, the trim age of circuits trimmed in 2010 varied by service area. That meant there would be a biased comparison of service areas when considering 2010 costs alone. Therefore, the need arose to determine the equivalency point on the ECI cost curve for the 2010 costs. This was done for each service area with the assistance of empirical knowledge from field personnel and ultimately provided DCI with the relative estimate of the actual cost experienced against the target trimming cycle. As a part of the 2011 revision of the cost curves, the existing curves were compared to the average costs per mile and cycles recorded in 2010 across each service area and adjusted accordingly.

The adjusted cost curves for each service area are shown in Figure 6 below.

Figure 6 - Cost Curves



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4. TTM Core Scenario Analysis

TTM core analysis deals with the impact of tree trimming programs embodied by the trim cycle and budget levels on the reliability of the system.

4.1. Analysis Scenarios

DCI analyzed two VM scenarios that were focused on trimming the entire circuits. The scenarios were mileage based and included: (1) a three-year cycle mileage-partitioned optimization; and, (2) a four-year cycle mileage-partitioned optimization.

4.1.1. Scenario 1 – Three-Year Cycle Mileage-Partitioned Optimization

This scenario was based on trimming one-third of each service area's mileage every year, or approximately 2,110 miles in total. This mileage optimization was partitioned-based, which means that individual mileage targets were assigned for each service area according to Table 2 below.

Table 2: Mileage Allocation for Each Service Area

Service Area	Mileage Target
Central	351
Dade City	123
Eastern	282
Plant City	416
South Hillsborough	251
Western	376
Winter Haven	311
Total	***2,110***

4.1.2. Scenario 2 – Four-Year Cycle Mileage-Partitioned Optimization

This scenario was based on trimming one-fourth of each service area's mileage every year, or approximately 1,582 miles in total. Similar to the three-year cycle, the mileage target was partition-based with specific mileage targets for each service area and is provided in Table 3 below.

Table 3: Mileage Allocation for Each Service Area

Service Area	Mileage Target
Central	263
Dade City	93
Eastern	211
Plant City	312
South Hillsborough	188
Western	282
Winter Haven	233
Total	***1,582***

The two scenarios were not constrained by a budget, meaning TTM identified a combination of circuits to trim which would provide the greatest reliability value at the lowest overall cost.

4.2. Analysis and Findings

The two scenarios were evaluated based on the trimming costs and expected reliability performance. The trimming costs were compared in terms of the NPV of the projected cash flows over a 10-year evaluation period. Reliability performance, expressed in terms of SAIDI minutes, was calculated for each year over the period.

As can be seen in Table 4 below, when compared, the four-year trim cycle costs approximately $12.9 million in NPV less than the three-year trim cycle over the 10-year period and results in a predicted average tree-related SAIDI of 23.62 minutes per year. The estimated average tree-related SAIDI associated with the three-year trim cycle is approximately 2.67 minutes lower. In other words, and as presented in Table 5 below, for the incremental investment of $12.9 million NPV over a 10-year period, Tampa Electric can avoid approximately 26.7 minutes of SAIDI in that 10-year period for the average cost of $484,000 per SAIDI minute avoided.

Table 4: Scenario NPV Analysis

	10-year VM Trim Budget NPV Value (in millions)	**10-Yr Total (Average) Tree SAIDI Minutes** (2012-2021)	**10-Yr Average Tree SAIDI Minutes (2012-2021)**	**Incremental 10-Yr VM Trim Cost per Tree SAIDI Minute Avoided (in millions)**
Three-year cycle	$ 81.64	209.49	20.95	$ 0.484
Four-year cycle	$ 68.70	236.23	23.62	N/A
Difference	$ 12.93	-26.74	-2.67	N/A
Change %	16%	-13%	-13%	N/A

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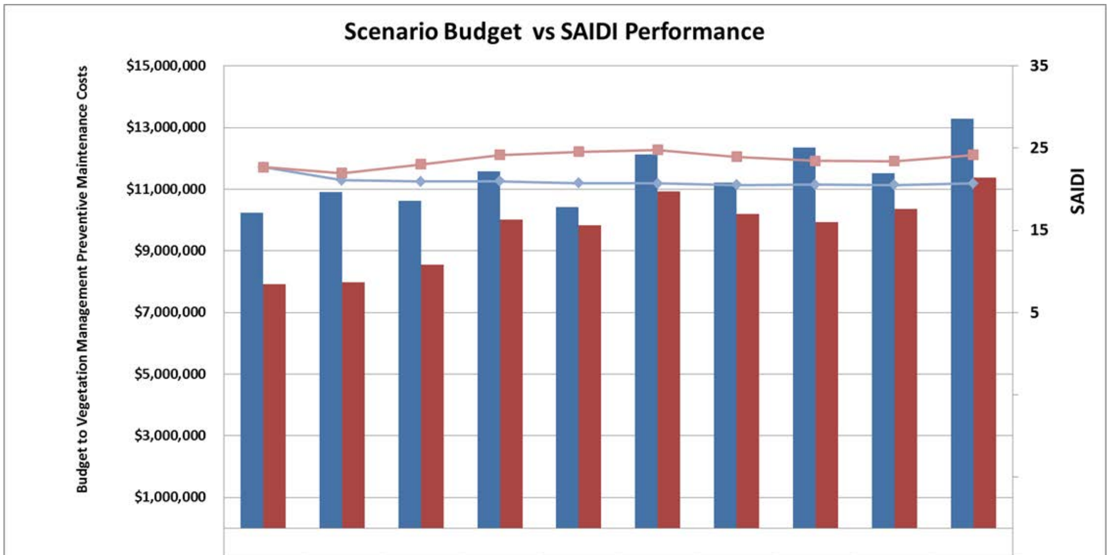
The graph in Figure 7 below provides the detail on how the above described scenarios fared against each other in terms of trimming cost and projected SAIDI each year from 2012 through 2021.

Figure 7 - Comparative Scenario Analysis



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1 - TECO 3 yr avg partitioned	$10,236,869	$10,910,516	$10,615,056	$11,583,564	$10,427,068	$12,126,631	$11,203,968	$12,351,944	$11,524,876	$13,292,529
2 - TECO 4 yr avg partitioned	$7,927,002	$7,972,141	$8,545,322	$10,005,958	$9,835,268	$10,934,681	$10,204,174	$9,923,788	$10,356,111	$11,374,998
1 - TECO 3 yr avg partitioned	22.71	21.09	20.95	20.98	20.74	20.71	20.53	20.55	20.53	20.72
2 - TECO 4 yr avg partitioned	22.71	21.96	23.02	24.19	24.56	24.78	23.95	23.46	23.43	24.18

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5. TTM Storm Scenario Analysis

5.1. TTM Storm Analysis Module Data and Assumptions

Since VM affects the amount of damage during major events, the TTM includes a module that allows for an analysis of potential storm impacts for each scenario. This is done by comparing scenarios on a wider range of cost classifications that include the following:

- Trim Budget – the cost of preventive trimming over the planning period which corresponds to the budget figures presented in Subsection 4.2;
- Corrective Maintenance Cost – the cost of reactive trim activity such as hot-spotting associated with each scenario;
- Normal Restoration Cost – the cost of restoring customers that experienced outages on a normal day as a result of the scenario parameters; and,
- Storm Restoration Cost – the cost of restoring customers during storm outages.

The first two cost classifications are sometimes referred to as "hard" costs since they are derived from day-to-day operations and thus there is high probability that they will indeed be incurred. The last two costs – normal and storm restoration – are sometimes referred to as "soft" costs as they will only be incurred during outages. These "soft" cost projections will be based on expected values and provide less assurance they will match the actual costs that occur in any single year. In the long run, however, when such actual costs are averaged out over a sufficient number of years, they are expected to approach the projected value.

5.1.1. Corrective Maintenance Costs

Corrective maintenance is assumed on a per scenario basis. Tampa Electric provided estimates for the current corrective maintenance spending at $546,523 for the three-year cycle program, as well as percentage change from this value for the four-year cycle scenario. As can be seen in Table 5 below, the corrective maintenance cost was kept constant for both scenarios for the first year, and adjusted by 30 percent for the remaining years for the four-year scenario. The 30 percent adjustment was based on Tampa Electric's past experience.

Table 5: Estimated Corrective Maintenance Costs per Scenario

	Relation to Base $0.55M	2012 Cost	2013-2021 Annual Cost
Three-year cycle	-	$ 546,523	$546,523
Four-year cycle	30% increase	$ 546,523	$ 710,480

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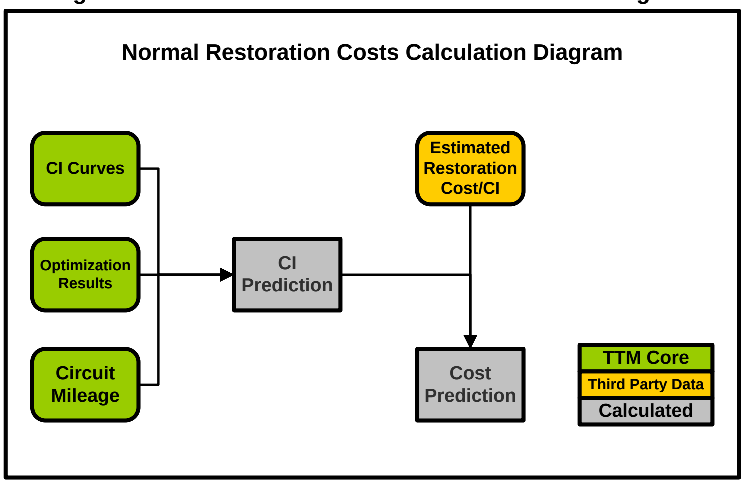
5.1.2. Normal Restoration Cost

The normal restoration cost is derived from SAIFI projections, as enabled by the CI curves discussed in Subsection 3.1.3, and estimated costs to restore a customer in normal conditions. This is shown in Figure 8 below.

Figure 8 – Normal Restoration Costs Calculation Diagram

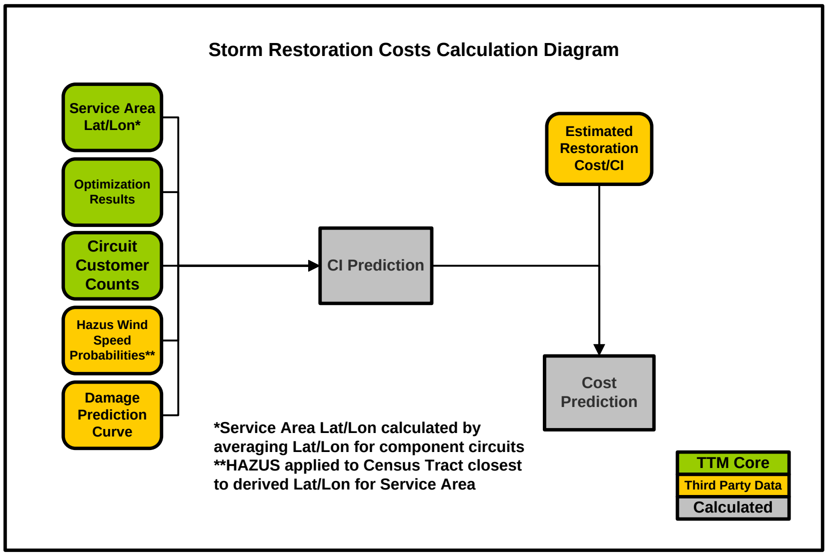


5.1.3. Storm Restoration Costs

Each circuit was assigned an expected wind speed, based on data from Federal Emergency Management Agency (FEMA)'s Hazards United States (HAZUS) database, used in estimating damage from disasters. HAZUS gives the return speed experienced in a particular census tract every 10, 20, 50, 100, 200, 500 and 1,000 years. DCI converted these into annual probabilities of 10 percent, 5 percent, 2 percent, 1 percent, etc., in order to derive an annual wind speed probability distribution and ultimately an expected wind speed value for each census tract. DCI then used the coordinates of each circuit (as derived in Subsection 2.1.1) for a given service area to estimate the center point of that service area, which then adopted the expected wind speed probability of the census tract closest to its center.

These wind speeds served as inputs to a damage prediction curve that also considered the number of years since a circuit had last been trimmed to generate an estimate of the percentage of customers on that circuit that would experience an outage. This CI prediction was then multiplied by the cost to restore one customer in storm conditions to derive the overall storm restoration cost. This is shown Figure 9 below.

Figure 9 - Storm Restoration Cost Calculation Diagram



5.2. Analysis and Findings

In addition to evaluating the preventive trim cost and reliability performance, which were discussed in Section 4 of this report, the two scenarios were compared based on the estimate of total VM program related costs. The total VM program cost includes all the costs associated with preventive trimming, corrective maintenance associated with vegetation, normal restoration costs of vegetation caused outages and storm related restoration costs. This approach monetizes the value of the reliability associated with each scenario and incorporates the costs of responding to day-to-day outages that are caused by trees. This allows for the comparison of different scenarios on a NPV total cost basis and the determination of which scenario that will provide the lowest total cost to the customers.

When compared using this method, the NPV of the total VM program costs associated with the four-year cycle is $3.1 million less than that associated with the three-year cycle, making it a better option. Figure 10 and Table 6 below provide a breakdown of the VM associated costs over the next 10 years.

Figure 10– Comparative Analysis of Overall Scenario Costs

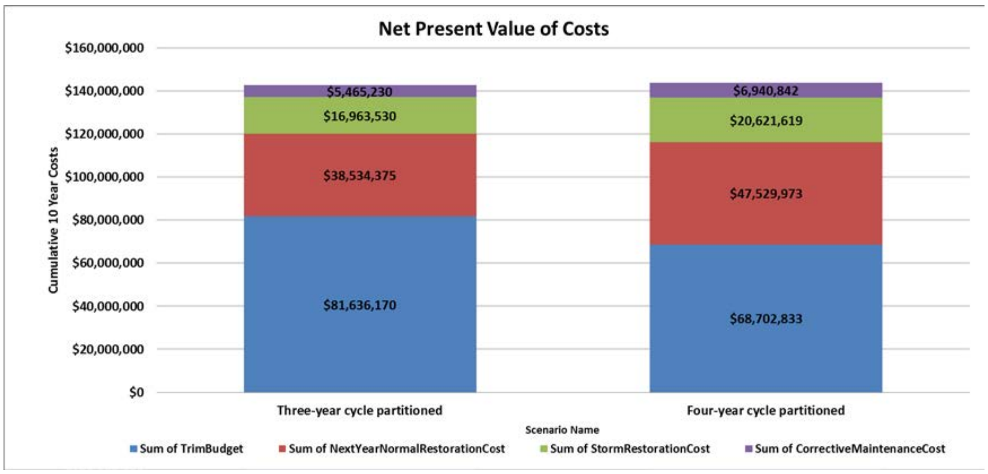


Table 6: 10-Year NPV of VM Program Costs

Scenarios	Cumulative Costs (2012 - 2021)				
	VM Trim Budget	Normal Restoration Costs from Tree Outages	VM Storm Restoration Costs	Corrective Maintenance Costs	Total VM Program Costs
Three-year cycle	$81.64	$38.53	$16.96	$5.47	$175.24
Four-year cycle	$68.70	$47.53	$20.62	$6.94	$172.17
Difference	$12.93	$-9.00	$-3.66	$-1.48	$3.06
Change %	16%	-23%	-22%	-27%	2%

Note: Cost figures are in millions of US$

2. Referring to page 12, Initiative 5: Geographic Information System (GIS), is TECO's entire transmission and distribution system inputted in its GIS? If no, how much of TECO's transmission and distribution system has been inputted and when will the remainder of the system be inputted?

A. Yes, Tampa Electric's entire transmission and distribution systems are inputted into the company's geographic information system.

3. On pages 19 and 20, Extreme Wind Loading Standards (EWL), TECO reported that the effective wind speed of a Grade B pole is approximately 116 miles per hour (mph) and that TECO's service territory is divided into two wind regions, 120 mph and 110 mph, according to the wind-loading map that National Electrical Safety Code (NESC) provides.

a) Does TECO use Grade B poles for both wind regions? If no, what grade poles are used for each wind region?

b) If yes, please justify using Grade B poles (116 mph) in the 120 mph zone.

A. a. Tampa Electric uses Grade B poles for both wind regions. An important note to clarify, the loading on the pole determines the grade of construction. The pole in itself does not determine if it is Grade B, C or extreme wind.

b. The pole in itself does not determine if it is Grade B, C or extreme wind. Tampa Electric ensures that the poles used will meet the strength and loading requirements for 116 mph for facilities 60 feet in height and below, and 120 miles per hour ("mph") for facilities exceeding 60 feet in height.

The heading "Extreme Wind Loading Standards" on page 19 could be titled "Combined Ice and Wind District Loading and Extreme Wind Loading Standards" which addresses the two types of wind loading standards for Grade B construction: National Electrical Safety Code ("NESC") Rule 250B and Rule 250C.

NESC Rule 250B addresses combined ice and wind district loading for light loading districts which requires a nine pounds per square foot wind pressure or approximately 60 mph winds. Applying the appropriate load and strength factors for Grade B construction, the effective wind speed is approximately 116 mph. Rule 250B is applicable to all facilities with conductors that do not exceed 60 feet above ground or water level.

NESC Rule 250C addresses the extreme wind loading and is applicable to all facilities with attached conductors that exceed 60 feet above ground or water level. Tampa Electric uses 120 mph as the design wind load for facilities meeting Rule 250C of Grade B construction.

4. Referring to page 22, Construction Standards, are there different types of Grade B poles? If yes, please explain the difference.

A. No, the pole in itself does not determine if it is Grade B, C or extreme wind. The loading on the pole determines the grade of construction. For example, a 45-foot class I pole used in a project that is designed and constructed to meet Grade B construction standards would be considered to be a Grade B pole. If the same pole is used in a design that exceeds Grade B construction, this pole would no longer be considered a Grade B pole. NESC Grade B construction for Light Loading District and Extreme Wind defines a set of ice, wind pressure, temperature, load and strength factors which are used for line design. Tampa Electric utilizes wood, pre-stressed concrete, ductile iron and spun concrete poles designed to meet the NESC Grade B loading requirements.

5. Referring to page 23, Table 1: Named Storms Affecting TECO, please provide the dollar amount removed from TECO's storm reserve account for the storms listed in Table 1.

A. Tampa Electric's Storm Damage Reserve was approved on February 23, 1995 by Order No. PSC-95-0255-FOF-EI in Docket No. 930987-EI. The table below shows the dollar amounts charged to the storm reserve account 228.1 by Tampa Electric for storm related expenses from the following named storms that were listed within the referenced Table 1:

Dollar Amounts Charged to Tampa Electric Storm Reserve Account		
Year	**Storm Name**	**Dollar Amounts**
2004	Charley	$14.5 Million
2004	Francis	$25.1 Million
2004	Jeanne	$34.8 Million
2012	Debby	$1.2 Million
2012	Isaac	$1.0 Million

6. Referring to page 25, Pole Loading, please provide the data TECO relies upon to conclude that using Grade B construction is the most cost-effective and reliable standard.

A. Tampa Electric relies on NESC rules, the wind profiles of the company's service area, knowledge of associated costs and experience to determine that Grade B construction is the safest, most cost effective and reliable standard.

Under the current NESC rules:

- Extreme Wind Loading is only required for structures greater than 60 feet above ground. For Tampa Electric, the additional cost to build to this standard would cost approximately $3,000 per mile. This additional cost to build to extreme winds as a standard for distribution facilities that rarely exceed 40 feet cannot be justified. The wind profiles for the Tampa Electric service area also do not support building to extreme wind standards as a common practice.

- Grade C construction is only allowable where there are no major crossings (roads, railways, waterways, etc.) and where any underbuilt communication facilities have the ability to protect their own system in case of a distribution contact. These limitations relegate Grade Construction to mainly to rural locations. The cost difference to increase Grade C construction to Grade B is currently approximately $30 per pole. This small incremental cost supports upgrading due to the 87 percent gain in structure strength for storm hardening when building to Grade B versus Grade C construction.

The following pages represent the study that was performed in 2007 to demonstrate that Grade B construction is the most cost-effective and reliable standard.

TECO
TAMPA ELECTRIC

Rebuild Hardening Perfectly Good Feeder
i.e., Major Throughafares, Critical Infrastructures
GRADE OF CONSTRUCTION Grade "Current Practice"
Cost per mile

Assumptions:
- Three phase 336 mcm, 2/0 neutral
- Two 2 inch comm cables
- 7 poles w/ one TX
- 5 poles w/ open Delta
- 3 poles w/ 3 Tx Bank

	Quantity	Poles that are to be changed out		Cost/item	Total
	22	Cost for stronger pole	45C4	$188.00	$4,136.00
	1	Cost for stronger pole	45C2	$274.74	$274.74
		Cost for stronger pole	45C1	$383.74	$0.00
	8	Cost for stronger pole	50C1	$383.74	$3,069.92
	4	Cost for stronger pole	55C1	$435.70	$1,742.80
		Cost for stronger pole	40H1	$323.00	$0.00
		Cost for stronger pole	45H1	$377.00	$0.00
		Cost for stronger pole	50H1	$533.00	$0.00
		Cost for stronger pole	55H1	$835.00	$0.00
		Cost for stronger pole	40H2	$355.00	$0.00
		Cost for stronger pole	45H2	$447.00	$0.00
		Cost for stronger pole	50H2	$672.00	$0.00
		Cost for stronger pole	55H2	$1,007.00	$0.00
		Cost for stronger pole	45H3	$843.00	$0.00
35		Cost for stronger pole	45H4	$992.00	
		15% Material Handling			$763.12
	35	Layout & Transfer three phase primary and neutral		$763.54	$26,723.90
	35	pole haul out		$109.22	$3,822.70
	35	Labor for pole install		$450.00	$15,750.00
	35	Labor for pole removals		$204.50	$7,157.50
	35	pole haul in		$109.22	$3,822.70
	4	arrester stations		$343.18	$1,372.72
	7	single phase transformers		$684.74	$4,793.18
	5	Open delta three phase transformer bank		$1,045.63	$5,228.15
	3	three phase transformer bank		$1,563.79	$4,691.37
	1	set of 3 SPST switches		$3,638.60	$3,638.60
	2	three phase corner poles		$757.24	$1,514.48
	5	fused single phase tap poles		$162.58	$812.92

		Cost/mile
Cost per mile to change out existing poles		**$89,314.80**
	Indeterminants	**$22,328.70**
	Total	**$111,643.49**

Cost to change out existing poles on the distribution system

Miles of Line	Cost/mile	Total
1	$111,643.49	**$111,643.49**

Rebuild Hardening Perfectly Good Feeder
i.e., Major Throughafares, Critical Infrastructures
GRADE OF CONSTRUCTION Grade Extreme Wind 120mph B
Cost per mile

Assumptions:

- Three phase 336 mcm, 2/0 neutral
- Two 2 inch comm cables
- 7 poles w/ one TX
- 5 poles w/ open Delta
- 3 poles w/ 3 Tx Bank

	Quantity	Poles that are to be changed out		Cost/item	Total
		Cost for stronger pole	45C4	$188.00	$0.00
	2	Cost for stronger pole	45C2	$274.74	$549.48
	2	Cost for stronger pole	45C1	$383.74	$767.48
	4	Cost for stronger pole	50C1	$383.74	$1,534.96
	1	Cost for stronger pole	55C1	$435.70	$435.70
		Cost for stronger pole	40H1	$323.00	$0.00
	7	Cost for stronger pole	45H1	$377.00	$2,639.00
	2	Cost for stronger pole	50H1	$533.00	$1,066.00
		Cost for stronger pole	55H1	$835.00	$0.00
		Cost for stronger pole	40H2	$355.00	$0.00
	8	Cost for stronger pole	45H2	$447.00	$3,576.00
	3	Cost for stronger pole	50H2	$672.00	$2,016.00
	3	Cost for stronger pole	55H2	$1,007.00	$3,021.00
	2	Cost for stronger pole	45H3	$843.00	$1,686.00
35	1	Cost for stronger pole	45H4	$992.00	$992.00
		15% Material Handling			$2,593.74
	35	Layout & Transfer three phase primary and neutral		$763.54	$26,723.90
	35	pole haul out		$109.22	$3,822.70
	35	Labor for pole install		$450.00	$15,750.00
	35	Labor for pole removals		$204.50	$7,157.50
	35	pole haul in		$109.22	$3,822.70
	4	arrester stations		$343.18	$1,372.72
	7	single phase transformers		$684.74	$4,793.18
	5	Open delta three phase transformer bank		$1,045.63	$5,228.15
	3	three phase transformer bank		$1,563.79	$4,691.37
	1	set of 3 SPST switches		$3,638.60	$3,638.60
	2	three phase corner poles		$757.24	$1,514.48
	5	fused single phase tap poles		$162.58	$812.92

		Cost/mile
Cost per mile to change out existing poles		**$100,205.58**
	Indeterminants	**$25,051.39**
	Total	**$125,256.97**

Cost to change out existing poles on the distribution system

Miles of Line	Cost/mile	Total
1	$125,256.97	**$125,256.97**

TECO TAMPA ELECTRIC

Rebuild Hardening Perfectly Good Feeder
i.e., Major Throughafares, Critical Infrastructures
Extreme Wind (120mph) Grade
Cost per mile

Assumptions:
Three phase 336 mcm, 2/0 neutral
Two 2 inch comm cables
7 poles w/ one TX
5 poles w/ open Delta
3 poles w/ 3 Tx Bank

	Quantity	Poles that are to be changed out		Cost/item	Total
		Cost for stronger pole	45C4	$188.00	$0.00
	4	Cost for stronger pole	45C2	$274.74	$1,098.96
	2	Cost for stronger pole	45C1	$383.74	$767.48
		Cost for stronger pole	50C1	$383.74	$0.00
		Cost for stronger pole	55C1	$435.70	$0.00
		Cost for stronger pole	40H1	$323.00	$0.00
	10	Cost for stronger pole	45H1	$377.00	$3,770.00
	2	Cost for stronger pole	50H1	$533.00	$1,066.00
		Cost for stronger pole	55H1	$835.00	$0.00
		Cost for stronger pole	40H2	$355.00	$0.00
	11	Cost for stronger pole	45H2	$447.00	$4,917.00
	3	Cost for stronger pole	50H2	$672.00	$2,016.00
	3	Cost for stronger pole	55H2	$1,007.00	$3,021.00
	2	Cost for stronger pole	45H3	$843.00	$1,686.00
38	1	Cost for stronger pole	45H4	$992.00	
		15% Material Handling			$2,751.37
	38	Layout & Transfer three phase primary and neutral		$763.54	$29,014.52
	38	pole haul out		$109.22	$4,150.36
	38	Labor for pole install		$450.00	$17,100.00
	38	Labor for pole removals		$204.50	$7,771.00
	38	pole haul in		$109.22	$4,150.36
	4	arrester stations		$343.18	$1,372.72
	7	single phase transformers		$684.74	$4,793.18
	5	Open delta three phase transformer bank		$1,045.63	$5,228.15
	3	three phase transformer bank		$1,563.79	$4,691.37
	1	set of 3 SPST switches		$3,638.60	$3,638.60
	2	three phase corner poles		$757.24	$1,514.48
	5	fused single phase tap poles		$162.58	$812.92

		Cost/mile
Cost per mile to change out existing poles		**$105,331.46**
	Indeterminants	**$26,332.87**
	Total	**$131,664.33**

Cost to change out existing poles on the distribution system

Miles of Line	Cost/mile	Total
1	$131,664.33	**$131,664.33**

TECO
TAMPA ELECTRIC

Rebuild Hardening Perfectly Good Feeder
i.e., Major Throughafares, Critical Infrastructures
GRADE OF CONSTRUCTION Grade B
Cost per mile

Assumptions:
- Three phase 336 mcm, 2/0 neutral
- Two 2 inch comm cables
- 7 poles w/ one TX
- 5 poles w/ open Delta
- 3 poles w/ 3 Tx Bank

	Quantity	Poles that are to be changed out		Cost/item	Total
	1	Cost for stronger pole	45C4	$188.00	$188.00
	5	Cost for stronger pole	45C2	$274.74	$1,373.70
	9	Cost for stronger pole	45C1	$383.74	$3,453.66
	8	Cost for stronger pole	50C1	$383.74	$3,069.92
	2	Cost for stronger pole	55C1	$435.70	$871.40
		Cost for stronger pole	40H1	$323.00	$0.00
	5	Cost for stronger pole	45H1	$377.00	$1,885.00
	1	Cost for stronger pole	50H1	$533.00	$533.00
	2	Cost for stronger pole	55H1	$835.00	$1,670.00
		Cost for stronger pole	40H2	$355.00	$0.00
	1	Cost for stronger pole	45H2	$447.00	$447.00
		Cost for stronger pole	50H2	$672.00	$0.00
		Cost for stronger pole	55H2	$1,007.00	$0.00
	1	Cost for stronger pole	45H3	$843.00	$843.00
35		Cost for stronger pole	45H4	$992.00	
		15% Material Handling			$2,122.00
	35	Layout & Transfer three phase primary and neutral		$763.54	$26,723.90
	35	pole haul out		$109.22	$3,822.70
	35	Labor for pole install		$450.00	$15,750.00
	35	Labor for pole removals		$204.50	$7,157.50
	35	pole haul in		$109.22	$3,822.70
	4	arrester stations		$343.18	$1,372.72
	7	single phase transformers		$684.74	$4,793.18
	5	Open delta three phase transformer bank		$1,045.63	$5,228.15
	3	three phase transformer bank		$1,563.79	$4,691.37
	1	set of 3 SPST switches		$3,638.60	$3,638.60
	2	three phase corner poles		$757.24	$1,514.48
	5	fused single phase tap poles		$162.58	$812.92

		Cost/mile
Cost per mile to change out existing poles		**$95,784.90**
	Indeterminants	**$23,946.22**
	Total	**$119,731.12**

Cost to change out existing poles on the distribution system

Miles of Line	Cost/mile	Total
1	$119,731.12	**$119,731.12**

TECO
TAMPA ELECTRIC

Rebuild Hardening Perfectly Good Feeder
i.e., Major Throughafares, Critical Infrastructures
GRADE OF CONSTRUCTION Grade C
Cost per mile

Assumptions:
- Three phase 336 mcm, 2/0 neutral
- Two 2 inch comm cables
- 7 poles w/ one TX
- 5 poles w/ open Delta
- 3 poles w/ 3 Tx Bank

Quantity	Poles that are to be changed out		Cost/item	Total
7	Cost for stronger pole	45C4	$188.00	$1,316.00
14	Cost for stronger pole	45C2	$274.74	$3,846.36
2	Cost for stronger pole	45C1	$383.74	$767.48
8	Cost for stronger pole	50C1	$383.74	$3,069.92
4	Cost for stronger pole	55C1	$435.70	$1,742.80
	Cost for stronger pole	40H1	$323.00	$0.00
	Cost for stronger pole	45H1	$377.00	$0.00
	Cost for stronger pole	50H1	$533.00	$0.00
	Cost for stronger pole	55H1	$835.00	$0.00
	Cost for stronger pole	40H2	$355.00	$0.00
	Cost for stronger pole	45H2	$447.00	$0.00
	Cost for stronger pole	50H2	$672.00	$0.00
	Cost for stronger pole	55H2	$1,007.00	$0.00
	Cost for stronger pole	45H3	$843.00	$0.00
35	Cost for stronger pole	45H4	$992.00	
	15% Material Handling			$1,413.98
35	Layout & Transfer three phase primary and neutral		$763.54	$26,723.90
35	pole haul out		$109.22	$3,822.70
35	Labor for pole install		$450.00	$15,750.00
35	Labor for pole removals		$204.50	$7,157.50
35	pole haul in		$109.22	$3,822.70
4	arrester stations		$343.18	$1,372.72
7	single phase transformers		$684.74	$4,793.18
5	Open delta three phase transformer bank		$1,045.63	$5,228.15
3	three phase transformer bank		$1,563.79	$4,691.37
1	set of 3 SPST switches		$3,638.60	$3,638.60
2	three phase corner poles		$757.24	$1,514.48
5	fused single phase tap poles		$162.58	$812.92

		Cost/mile
Cost per mile to change out existing poles		**$91,484.76**
	Indeterminants	**$22,871.19**
	Total	**$114,355.95**

Cost to change out existing poles on the distribution system

Miles of Line	Cost/mile	Total
1	$114,355.95	**$114,355.95**

7. Referring to page 26, Pole Loading Compliance.

a) When did TECO first start using the "PoleForeman" software?

b) Have there been any updates to the "PoleForeman" software since TECO first started using the software?

c) If yes, please provide the dates of the updates and the associated cost of the updates.

A. a. Tampa Electric began using the PoleForeman in 2007 when the software was purchased.

b. Yes, PoleForeman has been updated each year since the software was purchased. These annual software updates are included as part of the maintenance and services contract with the vendor of the PoleForeman software. Examples of the content of updates to the PoleForeman software include:

- 2007 NESC Updates
- 2012 NESC Updates
- General software enhancements and functional fixes
- New features and functionality
- Updates to construction specifications such as: pole line hardware, material strength ratings, sag tables, etc.

c. The table below shows the year and associated cost of the PoleForeman software updates:

Annual PoleForeman Update Costs	
Year of Update	**Associated Cost**
2007	$20,057
2008	$20,659
2009	$18,000
2010	$18,000
2011	$18,000
2012	$22,205
2013	$22,649
2014	$22,898
2015	$22,868

8. Referring to page 27, Underground Facilities - Standard Design, please provide a description of a "tree-retardant" cable.

A. A "tree-retardant" cable is constructed using crosslinked polyethylene ("XLPE") material to minimize the deterioration of cable insulation created by water intrusion. The industry has used the term "water trees" to describe this phenomenon due to images resembling trees seen in deteriorating cable insulation under a microscope.

9. Referring to page 32, Critical Infrastructure (CIF), please provide data summarizing the hardening of TECO's CIF and other types of distribution feeder hardening projects. Please provide this information in the following format for the years 2007 through 2018:

	Total	Number Hardened	O&M Cost	Capital Cost	Total Cost
Project					
Project					

A. The table below shows the summarized data for the hardening of Tampa Electric's Critical Infrastructure Facilities ("CIF") and other hardening projects:

	Total	Number Hardened	O&M Cost	Capital Cost	Total Cost
Port of Tampa	1	1	0.0	3.0	3.0
St. Joseph's Hospital	1	1	0.0	0.4	0.4
Downtown Network	18	18	0.0	0.4	0.4
Interstate Crossings - Distribution	31	16	0.0	1.6	1.6
Tampa International Airport	1	1	0.0	6.5	6.5
City of Tampa Tippin Water	1	1	0.0	0.9	0.9
Tampa General Hospital	1	1	0.0	5.5	5.5
Circuit 66042 Transmission Relocation	1	1	0.0	6.6	6.6
Conversion of 4kV circuits to 13kV	4	4	0.0	0.9	0.9
Concrete Foundation Remediation	1	8	0.0	0.8	0.8
Trans Ckt 230018 Remediation	1	76	0.0	0.7	0.7
Circuit 230014 Remediation	1	87	0.0	0.4	0.4

10. Referring to page 33, Table 2 - Summary of Benefits and Drawbacks of Overhead and Underground Electric Service:

a) For the underground benefits and drawbacks, please compare the expense and process between no tree-trimming expense versus more exposure due to storm surge or flooding.

b) Please provide the documentation referenced in Note 2 (page 34), that supports TECO's claim that the cost to install and maintain underground facilities is up to ten times the cost of overhead.

A. a. For underground facilities, there are no ongoing costs for vegetation management. Unfortunately, in the event of storm surge the damage to underground facilities and costs to properly cleaning and dry affected electrical system facilities/components will be significant. This lesson learned was obtained from performing mutual assistance in the northeast in the aftermath of Super Storm Sandy. Cleaning and drying the equipment is very time consuming and costly. In addition, if the facilities/components are impacted by saltwater, this equipment may require that it be immediately replaced.

b. Tampa Electric follows the Edison Electric Institute report "Out of Sight, Out of Mind?" published in January 2004 for the basis for differences in overhead and underground installation and maintenance costs. A complete copy of this report is included and starts on the next page:

EDISON ELECTRIC INSTITUTE

Out of Sight, Out of Mind?

A study on the costs and benefits of undergrounding overhead power lines

By:

Brad Johnson
Independent Energy Advisor

For:

Edison Electric Institute

January 2004

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Report Outline

- *How much does undergrounding improve electric reliability?*
- *Other benefits of undergrounding.*
- *The costs of undergrounding.*
- *Benefit/cost summary.*
- *Paying for undergrounding.*

Executive Summary

It is an unpleasant fact of modern day life – big storms such as hurricanes and ice storms cause major power outages. Sometimes these outages in heavily damaged areas can last for days or even weeks. In the post mortem that follows a major storm related power outage, there is almost always a public clamoring for burying overhead power lines. For many, it seems only intuitive that placing electric wires underground should protect them from severe storms.

This report provides a summary overview of previously completed studies [in the US and abroad] and examines historical performance data for underground and overhead lines to evaluate the benefits and costs of placing more of our existing overhead electric distribution infrastructure underground.

The report finds that burying overhead power lines has a huge price tag, costing about 10 times what it costs to install overhead power lines. When compared to overhead power systems, underground power systems tend to have fewer power outages, but the duration of these outages tends to be much longer. Underground power systems are also not immune from outages during storms. The bottom line – reliability benefits associated with burying existing overhead power lines are uncertain and in most instances do not appear to be to be sufficient to justify the high price tag that undergrounding carries.

There are however, other substantial benefits for burying existing overhead power lines, the most significant of which is improved aesthetics. Many communities and individuals want their power lines removed from sight. While the benefits derived from these kinds of undergrounding initiatives are difficult to quantify, they are real and they are substantial. Because these projects cannot be justified based on standard economic criteria, community and government decision makers often struggle to determine who should pay and who should benefit from undergrounding initiatives based on aesthetics.

The report concludes with summaries of innovative programs that communities and local governments have adopted to help pay for burying their overhead power lines.

Introduction

In the last decade, the US East Coast and Midwest regions have experienced several catastrophic "100 year storms." These storms have left widespread electric power outages that have lasted for several days (Figure 1).

Given the critical role that electricity plays in our modern lifestyle, even a momentary power outage is an inconvenience. A days-long power outage presents a major hardship and can be catastrophic in terms of its health and safety consequences, and the economic losses it creates.

Why then, don't we bury more of our power lines so they will be protected from storms?

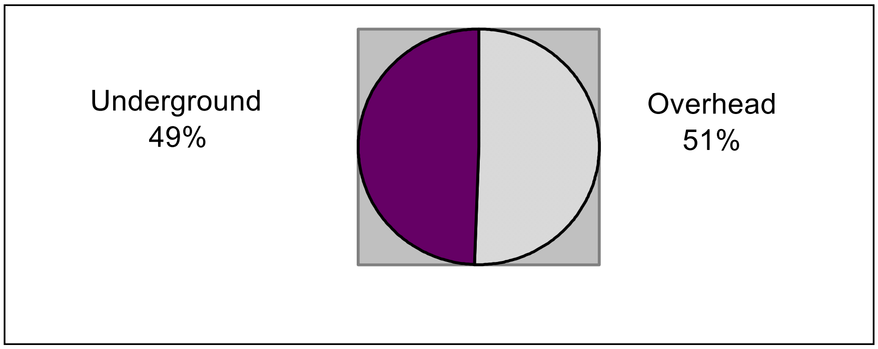
Figure 1: Electric Outages Caused by Severe Storms

Storm Event	Utility	Date	Customers Impacted	Outage Duration (Days)
Ice Storm	Kentucky Utilities	2003	146,000	8
Ice Storm	Duke	2002	1,375,000	9
	Carolina Power	2002	561,000	8
Ice Storm	KCPL	2002	305,000	10
Snowstorm	Carolina Power	2000	173,000	5
Hurricane Floyd	Virginia Power	1999	800,000	5
	Carolina Power	1999	537,000	6
	BGE	1999	490,000	5
Ice Storm	Pepco	1999	213,000	5
	BGE	1999	350,000	5
Ice Storm	Central Maine Power	1998	250,000	21
Ice Storm	Virginia Power	1998	401,000	10
Hurricane Fran	Virginia Power	1996	415,000	6
	Duke	1996	450,000	9
Ice Storm	Duke	1996	650,000	8
	Carolina Power	1996	61,000	4
	Carolina Power	1996	790,000	10

Source: Press Accounts of Storms

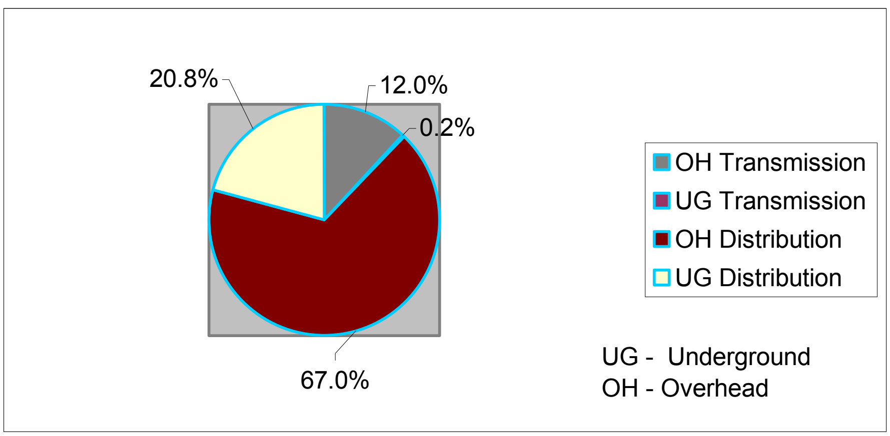
The fact is we already are placing significant numbers of power lines underground. Over the past 10 years, approximately half of the capital expenditures by US investor-owned utilities for ***new*** transmission and distribution wires have been for underground wires (Figure 2). Almost 80% of the nation's electric grid, however, has been built with overhead power lines (Figure 3). Would electric reliability be improved if more of these existing overhead lines were placed underground as well?

Figure 2: Capital Expenditures for New Power Lines (1993 – 2002 Average)



Source: FERC Form 1 Data 1993-2002

Figure 3: Miles of Overhead & Underground Line 2001 U.S. Total



Source: EEI Statistics

This report examines the major issues associated with undergrounding existing overhead power lines. It summarizes reliability comparisons between underground and overhead power lines and presents data on the benefits and costs of undergrounding. The report also presents summary information on programs that have been developed to fund undergrounding initiatives.

What the report finds is that burying existing overhead power lines does not completely protect consumers from storm-related power outages. However, underground power lines do result in fewer overall power outages, but the duration of power outages on underground systems tends to be longer than for overhead lines.

Also, undergrounding is expensive, costing up to $1 million/mile or almost 10 times the cost of a new overhead power line. This means that most undergrounding projects cannot be economically justified and must cite intangible, unquantifiable benefits such as improved community or neighborhood aesthetics for their justification. Determining who pays and who benefits from undergrounding projects can be difficult and often requires the establishment of separate government sponsored programs for funding.

I. How Much Does Undergrounding Improve Electric Reliability?

Many consumers assume that burying electric power lines will protect them from power outages caused by storms, and significantly improve overall power reliability. This is not necessarily the case.

Underground power systems are not immune from storm related outages. Figure 4 shows the equipment failures Baltimore Gas & Electric suffered on its underground system during Hurricane Isabel.

Figure 4: BGE Underground Failures Hurricane Isabel

Underground Equipment Item	Number of Failures
1000 kVA Network Transformers	3
Network Protectors	5
Switchgear Fuses	26
4kV D&W Fuses	17
Pad-mounted Switchgear	5
Pad-mounted Transformers	12
Primary Ductlilne Failures	8
Secondary Ductline Failures	10
Sections of Cable Renewed	14
Underground Cable Faults	100+

Source: Baltimore Gas & Electric Co.
"Major Storm Report: Hurricane Isabel" Attachment 5

Measuring Electric Reliability

Accurately measuring electric reliability is difficult. Most measures of electric reliability focus on two metrics:

- The **frequency** with which a customer sustains a power outage, i.e. the number of power outages/year, and
- The **duration** of power outages, i.e. the number of minutes/year a customer is without power.

For most utilities, it is extremely difficult to track the number of outages that occur on their systems and determine the number of customers impacted by these power outages. Utility switching actions, for example, can result in momentary outages that last only a fraction of a second.

For storm-related outages, the utility often relies on customers to provide notification that they are without power. If the customer does not report the outage, the utility may be unaware of it.

In spite of these difficulties, utilities worldwide collect data on both the frequency and duration of power outages. Increasingly, this data is used to measure utility performance against reliability standards, and utilities are rewarded and penalized based on how the data indicates they are performing.

Comparing the reliability of overhead power lines to underground power lines is even more difficult. Most utility outage-reporting systems do not separately track overhead and underground systems.

Another problem in trying to evaluate underground lines is that most underground circuits have at least some component above the ground. Installing monitoring equipment to distinguish between outages on the overhead and underground components of the same circuit is prohibitively expensive.

Comparing Overhead Reliability to Underground Reliability

Comparative reliability data indicate that the frequency of outages on underground systems can be substantially less than for overhead systems. However, when the duration of outages is compared, underground systems lose much of their advantage.

Figure 5 shows the frequency of power outages for overhead and underground electric systems around the world. The data show that the frequency of power outages on underground systems is only about one-third of that of overhead systems.

Figure 5: Yearly Power Interruptions per 100 km of Circuit

Utility	Voltage	Overhead	Underground
Integral Energy	HV	30.3	2.8
Integral Energy	LV	7.4	7.7
Energy Australia	HV	13.0	4.0
Citipower	HV	4.0	1.0
Mercury Energy	HV	30.5	7.1
Survey of Australian Utilities	HV & LV	23.6	5.6
France	LV	12.3	7.6
Finland	LV	8.0	4.0
Average		**16.1**	**5.0**

Note: km = kilometer, HV = high voltage, LV = low voltage

Source: "The Putting Cables Underground Working Group Report"
http://www.dcita.gov.au/cables/econ/econ_9a.htm

Figure 6 compares the duration of power outages for overhead and underground systems for UK utilities. This data shows that in 1996 and 1997, underground circuits were actually ***less*** reliable than overhead circuits. Over the 10-year period, however, the duration of outages for underground was about half of what it was for overhead.

Figure 6: Thousands of Customer Minutes Lost per 100 km of Circuit: UK Utilities

	1996/97		10 Year Average	
Utility	Overhead	Underground	Overhead	Underground
Eastern	2.5	4.5	7.5	3.5
East Midland	3.5	5.0	7.5	4.0
Manweb	3.5	3.5	5.0	4.5
Midlands	6.5	5.0		1.0
Northern	1.8	3.0	4.8	4.0
NORWEB	2.8	3.5	3.5	3.0
SEEBOARD	6.5	6.0	20.0	5.5
Southern	3.0	3.0	7.0	3.5
SWALEC	3.8	6.5		
Southern Western	2.0	4.0	5.5	5.5
Yorkshire	4.5	4.0	2.8	3.5
Scottish	3.5	2.5	2.0	2.0
Average	**3.7**	**4.2**	**6.6**	**3.6**

"The Putting Cables Underground Working Group Report"
http://www.dcita.gov.au/cables/econ/econ_9a.htm

Figure 7 presents data from a 2000 report issued by the Maryland Public Service Commission. Maryland utilities were asked to select "comparable" overhead and underground feeders and provide comparative reliability data for an historical period.

Based on the data summarized in Figure 7, the Maryland commission concluded in its final report that the impact of undergrounding on reliability was "unclear."[1]

Figure 7: Maryland Overhead vs. Underground Feeder Reliability Comparison[1]

	Overhead	Avg	Underground	Avg
Allegheny Power				
1996 SAIFI	0.11	0.6	0.28	0.8
1997 SAIFI	1.73		0.91	
1998 SAIFI	0.04		1.29	
1996 SAIDI	25.16	51.6	49.49	236.8
1997 SAIDI	124.96		569.88	
1998 SAIDI	4.59		91.07	
BGE				
1997 SAIFI	3.43	2.6	0.58	1.2
1998 SAIFI	0.45		1.72	
1999 SAIFI	3.84		1.39	
1997 SAIDI	65.00	152.7	178.00	130.0
1998 SAIDI	242.00		94.00	
1999 SAIDI	151.00		118.00	
Conectiv				
1997 SAIFI	1.84	0.8	1.25	1.0
1998 SAIFI	0.29		1.47	
1999 SAIFI	0.34		0.21	
1997 SAIDI	129.04	65.6	11.80	53.3
1998 SAIDI	23.48		129.61	
1999 SAIDI	44.30		18.59	
Pepco				
1997 SAIFI	2.59	2.1	0.22	0.7
1998 SAIFI	2.47		0.93	
1999 SAIFI	1.31		1.07	
1997 SAIDI	4.55	3.2	2.21	2.1
1998 SAIDI	0.78		0.71	
1999 SAIDI	4.39		3.29	

[1] Excludes major storms

Source: "Report to the Public Service Commission of Maryland on the Selective Undergrounding of Electric Transmission & Distribution Plant" Februrary 14, 2000.

Note:
SAIFI = Total Number of Customers Interrupted/Total Customers

SAIDI = Sum of All Customer Interruption Minutes/Total Customers

[1] "Report to the Public Service Commission of Maryland on the Selective Undergrounding of Electric Transmission and Distribution Plant," prepared by the Selective Undergrounding Working Group; February 14, 2000; page 2

Figure 8 summarizes five years of underground and overhead reliability comparisons for North Carolina's investor-owned electric utilities – Duke Energy, Progress Energy Carolinas and Dominion North Carolina Power. The data indicate that the frequency of outages on underground systems was 50% less than for overhead systems, but the average duration of an underground outage was 58% longer than for an overhead outage.

In other words, for the North Carolina utilities, an underground system suffers only about half the number of outages of an overhead system, but those outages take almost 1.6 times longer to repair.

Based on this data, Duke Power has concluded, "underground distribution lines will improve the potential for reduced outage interruption during normal weather, and limit the extent of damage to the electrical distribution system from severe weather-related storms. However, once an interruption has occurred, underground outages normally take significantly longer to repair than a similar overhead outage."[2]

Figure 8: North Carolina Reliability Comparison of Overhead & Underground Feeders 1998-2002

Reliability Category	Overhead	Underground
System interruption rate per mile	0.6	0.3
Tap line interruption rate per mile	0.4	0.2
Average outage duration (minutes)	92.0	145.0
Service conductor interruptions per 1000 customers	9.7	9.6

Source: "The Feasibility of Placing Electric Distribution Facilities Underground"
North Carolina Utilities Commission, November 2003

Discussion

The following summary points, taken from reports produced by utilities and conversations with industry experts, provide additional information on the reliability characteristics of overhead and underground power lines.

- Overhead lines tend to have more power outages primarily due to trees coming in contact with overhead lines.[3]

[2] "North Carolina Public Utility Commission Study Undergrounding Reliability Discussion" Duke Power," Duke Power

[3] Duke Power

- It is relatively easy to locate a fault on an overhead line and repair it. A single line worker, for example, can locate and repair a fuse. This results in shorter duration outages.[4]
- Underground lines require specialized equipment and crews to locate a fault, a separate crew with heavy equipment to dig up a line, and a specialized crew to repair the fault. This greatly increases the cost and the time to repair a fault on an underground system.[5]
- In urban areas, underground lines are four times more costly to maintain than overhead facilities.[6]
- Underground lines have a higher failure rate initially due to dig-ins and installation problems. After three or four years, however, failures become virtually non-existent.[7]
- As underground cables approach their end of life, failure rates increase significantly and these failures are extremely difficult to locate and repair. Maryland utilities report that their underground cables are becoming unreliable after 15 to 20 years and reaching their end of life after 25 to 35 years.[8]

It is unlikely that 100% of the circuit from the substation to the customer can be placed entirely underground.

This leaves the circuit vulnerable to the same types of events that affect other overhead lines, e.g. high winds and ice storms.

- Pepco found that customers served by 40-year-old overhead lines had better reliability than customers served by 20-year-old underground lines.[9]
- Two Maryland utilities, Choptank and Conectiv, have replaced underground distribution systems with overhead systems to improve reliability.[10]
- Water and moisture infiltration can cause significant failures in underground systems when they are flooded, as often happens in hurricanes.[11]
- Due to cost or technical considerations, it is unlikely that 100% of the circuit from the substation to the customer can be placed entirely underground. This leaves the circuit vulnerable to the same types of events that impact other overhead lines, e.g. high winds and ice storms.

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[4] North Carolina Utilities Commission

[5] North Carolina Utilities Commission

[6] "The Feasibility of Placing Electric Distribution Facilities Underground," North Carolina Utilities Commission, November 2003

[7] Duke Power

[8] "Report to the Public Service Commission of Maryland on the Selective Undergrounding of Electric Transmission and Distribution Plant," prepared by The Selective Undergrounding Working Group; February 14, 2000; page 9

[9] "Report to the Public Service Commission of Maryland on the Selective Undergrounding of Electric Transmission and Distribution Plant," prepared by The Selective Undergrounding Working Group; February 14, 2000; page 2, page 9

[10] "Report to the Public Service Commission of Maryland on the Selective Undergrounding of Electric Transmission and Distribution Plant," prepared by the Selective Undergrounding Working Group; February 14, 2000; page 9

[11] Duke Power

II. Other Benefits of Undergrounding

One of the most commonly cited benefits of undergrounding is the removal of unsightly poles and wires. Local communities and neighborhoods routinely spend millions to place their existing overhead power lines underground.

Similarly, when given the option, builders of new residential communities will often pay a premium of several thousand dollars/home to place the utilities underground. These "aesthetic" benefits are virtually impossible to quantify but are, in many instances, the primary justification for projects to place existing power lines underground.

The "aesthetic" benefits are virtually impossible to quantify but are, in many instances, the primary justification for projects to place existing power lines underground.

Underground lines do have other benefits. In 1998, Australia completed a major benefit/cost analysis of undergrounding all existing power lines in urban and suburban areas throughout the country.[12] The study cost more than $1.5 million Australian ($1.05 million US at current rates), and represents what may be the most comprehensive undertaking to date to quantify the benefits and costs related to undergrounding.

In addition to the value of improved aesthetics (which the Australian study did not attempt to quantify except as it affected property values) the study identified the following potential benefits related to undergrounding that it attempted to quantify:

- Reduced motor-vehicle accidents caused by collisions with poles
- Reduced losses caused by electricity outages
- Reduced network maintenance costs.
- Reduced tree-pruning costs
- Increased property values
- Reduced transmission losses due to the use of larger conductors
- Reduced greenhouse-gas emissions (lower transmission losses)
- Reduced electrocutions
- Reduced brushfire risks, and
- Indirect effects on the economy such as employment.

Of this list, only four items were deemed significant in the study's benefit/cost calculus. Figure 9 summarizes the values the Australian study calculated for each of these benefits. They included:

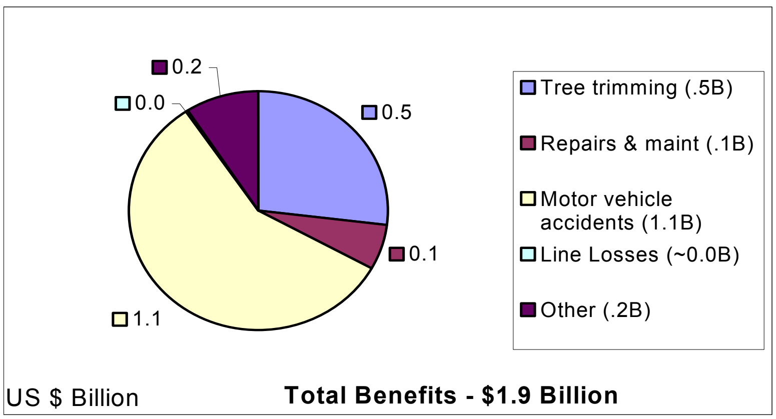
- Motor-vehicle accidents
- Maintenance costs
- Tree-trimming costs, and
- Line Losses.

The Australian list of benefits does not include improved reliability as a significant benefit of undergrounding. It identifies the reduction in losses from motor vehicle accidents as the largest benefit from undergrounding – something utilities have no control over (Figure 9).

[12] "The Putting Cables Underground Working Group Report" (http://www.dcita.gov.au/cables/report_x.htm#intro)

The US has never conducted a national undergrounding study comparable to the one conducted by Australia. Undergrounding studies in the US have been regional in nature, and have focused on the costs rather than the benefits of undergrounding.

**Figure 9: 20 Year Underground Benefit Projection
Australian Underground Study**



Source: The Putting Cables Underground Working Group Report (http://www.dcita.gov.au/cables/report/chap_4.htm)

III. The Costs of Undergrounding

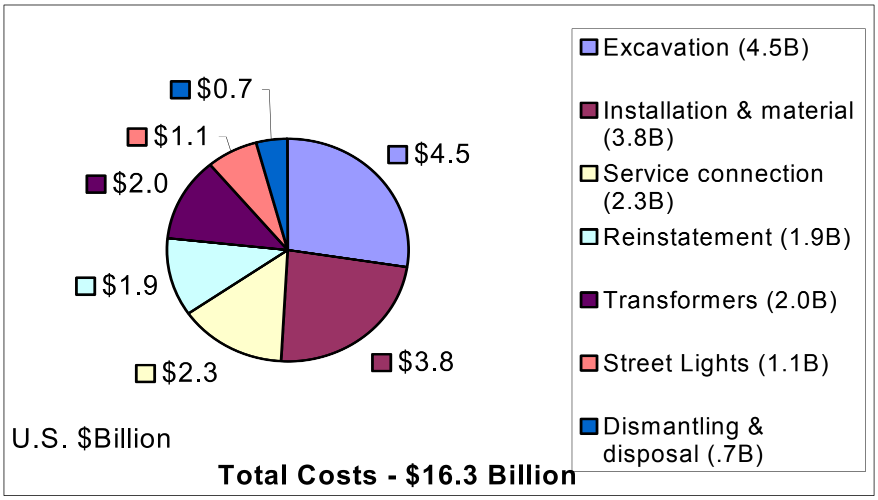
The Australian study performed an extensive analysis of underground costs, and developed a national costing model to estimate costs for undergrounding existing overhead power lines in urban and suburban areas. The results of that model are summarized on page 13 in Figures 10 and 10a.

In the U.S., the North Carolina Utilities Commission recently estimated it would take its three investor-owned utilities 25 years to underground all of their existing overhead distribution systems at a cost of approximately $41 billion. This six-fold increase in the existing book value of the utilities' current distribution assets would require a 125% rate increase.[13]

In other words, consumers would have to pay more than twice as much for electricity to enjoy the "benefits" of underground lines.

[13] "The Feasibility of Placing Electric Distribution Facilities Underground," North Carolina Utilities Commission, November 2003

**Figure 10: Underground Cost Projection
Australian Underground Study**



Source: The Putting Cables Underground Working Group Report (http://www.dcita.gov.au/cables/report/report_x.htm#Intro)

**Figure 10a: Underground Cost Summary
Australian Underground Study**

Total Cost (US $Billion)	$/Customer	$/Mile
$ 16.3	$ 3,856	$ 360,207

Source: The Putting Cables Underground Working Group Report (http://www.dcita.gov.au/cables/report/report_x.htm#Intro)

Underground cost data for other U.S. utilities is summarized in Figure 11, which indicates that the cost of placing overhead power lines underground is five to 10 times the cost of new overhead power lines.

Figure 11: Utility Underground Costs

	Average Cost/ Mile
Allegheny Power[1]	$ 764,655
BGE[1]	$ 952,066
Pepco[1]	$ 1,826,415
Conectiv[1]	$ 728,190
Va Power[2]	$ 950,000
California[3]	$ 500,000
FPL[4]	$ 840,000
Georgia Power[5]	$ 950,400
Puget Sount Energy[7]	$ 1,100,000
Average Overhead Line [6]	***$ 120,000***

Sources:
[1] Maryland Selective Undergrounding Working Group
[2] Dare County North Carolina Underground Study
[3] "Utility Undergrounding Programs", Scientech, May 2001, page 2
[4] "Utility Undergrounding Programs", Scientech, May 2001, page 3
[5] "Utility Undergrounding Programs", Scientech, May 2001, page 4
[6] "Utility Undergrounding Programs", Scientech, May 2001, page 4
[7] Puget Sound Energy

Figure 12 puts the U.S. underground cost data in perspective. It illustrates that, at a cost of $1 million/mile, a new underground system would require an investment of more than ten times what the typical U.S. investor owned utility currently has invested in distribution plant.

Figure 12: Investment Statistics IOU Distribution Plant

Investment Category	Existing Plant	New Underground
$/Customer[1]	$ 2,199	$29,854
$/Mile	$ 73,666	$1 Million

[1] Assumes U.S. average of 33.5 customers/mile of IOU distribution line
Source: NRECA Statistical Comparison
http://www.nreca.org/nreca/About_Us/Our_Members/Statistics/Statistics

Other factors also can result in substantial additional customer costs for undergrounding projects. These include:

- Electric undergrounding strands other utilities, e.g. cable and telephone companies, which must assume 100% of pole costs if electric lines are underground. These additional non-electric costs will likely be passed on to cable and telephone consumers.

- Customers may incur substantial additional costs to connect homes to newly installed underground service, possibly as much as $2,000 if the household electric service must be upgraded to conform to current electric codes.

Both the Australian and US studies on undergrounding have identified significant issues related to who assumes the burden for underground costs. If utilities were told they must underground a significant portion of their overhead power lines, who would pay for it and who would get their power lines placed underground first?

If the costs of undergrounding are fully allocated, only the wealthy may be able to afford it. On the other hand, if undergrounding is financed or socialized through a broad-base tax or electricity rates, people may end up paying for undergrounding projects that do not get to their neighborhoods for a decade or more (or after they have already moved).

Some innovative approaches being used to fund undergrounding projects are discussed in the final section of this report.

IV. Benefit/Cost Summary

Based on the projected benefits and costs for undergrounding much of its existing urban and suburban power lines, the Australian study calculated that the benefits would offset only about 11% of total costs (Figure 13).

**Figure 13: Projected 20 Year Costs and Benefits
Australia Underground Study**

Quantifiable Costs (US $Billion)		Quantifiable Benefits (US $ Billion)	
Excavation	$ 4.5	Motor vehicle accidents	$ 1.1
Installation & material	$ 3.8	Tree trimming	$ 0.5
Service connection	$ 2.3	Other	$ 0.2
Transformers	$ 2.0	Repairs & maint	$ 0.1
Reinstatement	$ 1.9	Line Losses	~0.0
Street Lights	$ 1.1		
Dismantling & disposal	$ 0.7		
Total	**$ 16.3**	**Total**	**$ 1.9**

*Source: The Putting Cables Underground Working Group Report
(http://www.dcita.gov.au/cables/report/report_x.htm#Intro)*

For the US, no comparable benefit cost analysis exists. However, based on the high costs of undergrounding projected in Figure 11, it appears that placing existing overhead lines underground is difficult to justify economically. Today, most undergrounding costs appear to be justified by aesthetic and public-policy considerations.

V. Paying For Undergrounding

In-spite of its high cost and lack of economic justification, undergrounding is very popular across the country. In nine out of 10 new subdivisions, contractors bury power lines.[14] In addition, dozens of cities have developed comprehensive plans to bury or relocate utility lines to improve aesthetics, including:[15]

- San Antonio, Texas
- Colorado Springs, Colorado
- New Castle, Delaware
- Saratoga Springs, New York
- Williamsburg, Virginia
- Tacoma, Washington
- Frederick, Maryland.

For new residential construction, utilities vary on how they charge for the cost of providing underground services. A sample of these policies is provided in Figure 14.

Figure 14: Sample Residential Undergrounding Requirements

Utility	State	Requirement
SDG&E, PGE & SCE	CA	Customer/Developer pays for trenching & backfilling. Utility pays remaining costs.
Atlantic City Electric	NJ	Customer/Developer pays $802.74 + $4.35 per front foot for each home. Utility pays remaining costs.
Cobb Electric Membership Corp.	GA	Customer/developer pays $260 per customer. Utility pays remaining costs.
Green Mountain Power	VT	Customer/Developer pays for trenching & backfilling. Utility pays remaining costs.
Nantucket Electric Co.	MA	The utility pays up to $837.85. The customer pays the remaining costs.
Consolidated Edison	NY	The utility charges the customer the diferential in charges for equivalent overhead construction
Mississippi Power	MS	Developer pays the cost differential above what it would cost to install overhead lines

Source: "Utility Undergrounding Programs", Scientech, May, 2001

When it comes to converting existing overhead lines to underground, a variety of programs are being utilized. They include special assessment areas, undergrounding districts, and state and local government initiatives. Details are provided below.

[14] "Utility Undergrounding Programs," Scientech; May 2001; page 6

[15] "Utility Undergrounding Programs," Scientech; May 2001; page 6

Special Assessment Areas

Several communities are establishing "special assessment areas," where subscribers pay extra on their monthly bill to fund the underground project. These areas are typically created through a petition of the majority of the property owners in an area.

Commonwealth Electric in Massachusetts has used special assessments since 1970 to fund burial efforts in historic communities such as Nantucket. One drawback to special assessments is that the total revenue collected is often minimal, requiring utilities to extend the schedule for undergrounding over an extended period of time.[16]

Undergrounding Districts

Another approach employed in California and Oregon is the establishment of "underground districts."

In California, the public utility commission collects a percentage of revenue from wire-based utilities for a special undergrounding fund. To receive these funds, a community must form an undergrounding district, approved by at least 70% of the property owners in that district. The property owners also must agree to pay the $500 to $2,000 it costs to connect their homes to a new underground system.[17]

Hawaii

Hawaii Electric has a program where it pays for up to one-third of the cost to place existing neighborhood electric distribution lines underground. Hawaii Electric will undertake the conversion as part of a community or government-initiated underground project, subject to public utility commission approval. The program does not include transmission lines.[18]

Hawaii Electric has a program where it pays for up to one-third of the cost to place existing neighborhood electric distribution lines underground.

South Carolina Electric and Gas

SCE&G has established a special undergrounding program, approved by the South Carolina Public Service Commission. Under the program, if the local municipality agrees to contribute a matching amount, SCE&G contributes .5% of the gross receipts it is obligated to pay to the municipality. This money goes into a special underground fund.[19]

Dare County North Carolina

In 1999 the North Carolina legislature passed a law allowing Dare County on North Carolina's Outer Banks to form a special utility district for the purpose of funding the conversion of existing overhead power lines to underground.

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[16] "Utility Undergrounding Programs," Scientech; May 2001; page 5

[17] "Utility Undergrounding Programs," Scientech; May 2001; page 5

[18] "Utility Undergrounding Programs," Scientech; May 2001; page 36

[19] "Utility Undergrounding Programs," Scientech; May 2001; page 38 and phone conversation with SCE&G

Under the legislation, once the utility district is created, the county's electric supplier, Dominion Virginia Power, is required to collect a maximum of $1/month from residential customers in the county and a maximum of $5/month from all other customers. These funds are placed in a special undergrounding fund, managed by Dominion Virginia Power, to be used on a pay-as-you-go basis to convert the county's existing overhead power lines to underground.

As of 2003, Dare County has not yet elected to form the special utility district. One of the reasons is that two communities in the county, Duck and Southern Shores, have objected to the special assessment. Both of these communities already have underground electric systems they paid for through development fees or special property-tax assessments. Residents in these communities believe it is unfair for them to pay for undergrounding the electric system for other county residents.

In communities in Dare County, N.C., residents who have already paid for underground systems through development fees or tax assessments object to a monthly assessment to fund underground conversion throughout the remainder of the county.

Several other counties in North Carolina and the Tidewater area of Southeast Virginia are studying the 1999 North Carolina legislation with the thought that they may seek similar legislation for their areas.

VI. Conclusion

Placing existing power lines underground is expensive, costing approximately $1 million/mile. This is almost 10 times the cost of a new overhead power line.

While communities and individuals continue to push for undergrounding—particularly after extended power outages caused by major storms—the reliability benefits that would result are uncertain, and there appears to be little economic justification for paying the required premiums**.**

"If a 10 percent return is imputed to the great amounts of capital freed up by building overhead instead of underground line, the earnings alone will pay for substantial ongoing overhead maintenance."

--Maryland Public Service Commission

Indeed, in its study of the undergrounding issue, the Maryland Public Service Commission concluded, "If a 10 percent return is imputed to the great amounts of capital freed up by building overhead instead of underground line, the earnings alone will pay for substantial ongoing overhead maintenance," implying that utilities could have more resources available to them to perform maintenance and improve reliability on overhead lines if they invested less in new underground facilities. [20]

For the foreseeable future, however, it appears that the undergrounding of existing overhead power lines will continue, justified primarily by aesthetic considerations—not reliability or

[20] "Report to the Public Service Commission of Maryland on the Selective Undergrounding of Electric Transmission and Distribution Plant," prepared by The Selective Undergrounding Working Group; February 14, 2000; page 3

economic benefits. Many consumers simply want their power lines placed underground, regardless of the costs. The challenge for decision makers, is determining who will pay for these projects and who will benefit.

There are several undergrounding programs around the country that are working through these equity issues and coming up with what appear to be viable compromises. Once a public-policy decision is reached to pursue an undergrounding project, it is worthwhile for the leaders involved to evaluate these programs in more detail to determine what is working, and what is not.

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11. On page 37, TECO reports that a "higher wind speed has been applied" to its transmission system "when the company determined that the circuit would be very difficult to restore." Does this practice apply to the distribution system as well?

A. Tampa Electric's distribution system is constructed in areas where access is not a major concern. Therefore, restoration of the distribution system is not an issue due to access, and higher wind speed construction is not required based solely on the location of the facilities.

12. Referring to page 38, Design Philosophy - Wind Strength Requirements, what is the difference between designing and implementing substation structures to withstand a wind load of 120 mph and 130 mph?

A. Substation structures that are designed to different wind loads require differences in the actual steel structure as well as the supporting foundations. For example, when designing and implementing a substation that can withstand a wind speed of 130 mph, over a substation that is designed to withstand 120 mph, requires the steel substation structure and the supporting foundation to be larger and stronger to accommodate the increased loading produced by the higher wind speed.

13. On page 39, Protection, TECO reported that animal protection covers are installed on all new 13 kV bushings, lightning arrestors, switches, and leads. Are animal protection covers installed on the higher kV equipment? Please explain your answer.

A. No, the animal outage and contact issues within substations are on the distribution equipment and buses that are operated at 13 kV. Animal protection covers are not rated for transmission level voltages. The transmission equipment operated at 69 kV, 138 kV and 230 kV have greater spacing distance requirements between conductors and grounded structures. Squirrels, rodents, medium and small size birds, and frogs are the majority of culprits that cause problems on energized substation equipment.

14. On page 50, Overhead to Underground Conversion of interstate highway crossings, TECO reported, "all remaining overhead crossings will be converted to underground ..."

a) How many overhead interstate highway crossings has TECO already converted?

b) How many overhead interstate highway crossings are left to be converted?

A. a. Through 2015, Tampa Electric has converted a total of 16 interstate highway crossings.

b. There are 15 remaining interstate highway crossings left to be converted. The company's plan for undergrounding these remaining crossing will be in conjunction with other work required on those distribution line sections such as during a road widening or re-conducting project.

15. Referring to page 51, Submersible Padmount Switchgear, please provide details (dates, cost, the duration of the project) on TECO's plans to install switchgears at the hospitals served by TECO.

A. In 2015, Tampa Electric began working with one hospital to replace three live-front switchgear with submersible switchgear. Two of the switchgear have automatic transfer capability while the third switchgear is manually operated. The cost for the three switchgear including installation is approximately $145,000. Tampa Electric is projecting to have this project complete during the third quarter of 2016.

In 2016, Tampa Electric began working with another hospital to replace one automatic transfer live-front switchgear and two manual live-front switchgear with submersible switchgear. One of the switchgear will have automatic transfer capability while the other two switchgear will be manually operated. The cost for the three switchgear including installation is approximately $137,000. Tampa Electric is projecting to have this project complete during the third quarter of 2016.

16. Referring to page 62, Joint Use Pole Attachment Audit, since the joint use attachment audit is on an eight-year cycle, are all of the joint use attachments inspected in one year or over eight years?

A. Tampa Electric's joint-use pole attachment audit typical takes between one to three years to complete. To meet the requirement of having the audit completed every eight years, the company initiates the pole attachment audit every five years to ensure compliance.

17. Did TECO make any updates or modifications to its Storm Hardening Plan or Attachment Standards and Procedures?

a) If yes, did TECO seek input from third party attachers as required by Rule 25-6.0342(6), Florida Administrative Code (F.A.C.), Electric Infrastructure Storm Hardening?

a. If yes, who responded and provide a summary of their comments and/or suggestions?

b. If no, please explain why not.

A. a. Yes, Tampa Electric made updates and modifications to the company's attachment standards and procedures. Prior to making the modification to streamline the process for unauthorized attachments and unpermitted service drops, the company worked with Brighthouse Networks. This modification provided benefits to Tampa Electric, as well as Brighthouse, in assisting to meet the requirement to harden the system.

b. Not Applicable.

18. Please provide the effect of TECO's electric infrastructure improvements on reducing storm restoration cost and customer outages as required by Rule 25-6.0342(4)(d), F.A.C. Please include the original 2007 analysis and any updates to the analysis. If no updates have been performed, please explain why not.

A. Tampa Electric anticipates that the storm hardening improvements that have been performed and continues will reduce the amount of damage as a result of a hurricane. The company expects this reduction in damage will consequently diminish both restoration cost and customer outages. Tampa Electric has not had any hurricanes impact our service territory that could afford the opportunity to compare and evaluate the performance of the storm hardening investments the company has made. Because of this, no updates to the 2007 analysis have been made. The original analysis from 2007 is attached on the next page:

Rule 25-6.0342 - Tampa Electric Company Storm Hardening Plan

			Actual/Estimated Utility Costs						Estimated Benefits to Utility Customers: Impact on Storm Restoration Costs			Estimated Benefits to Utility Customers: Impact on Storm Caused Outages			Other Estimated Company Benefits			Estimated Benefits toThird Party Attachers: Impact on Storm Restoration Costs			Estimated Benefits toThird Party Attachers: Impact on Storm Caused Outages		
	Activity	Docket No.	2004	2005	2006	2007	2008	2009	2007	2008	2009	2007	2008	2009	2007	2008	2009	2007	2008	2009	2007	2008	2009
(a)	**Wooden Pole Inspections.**	060078-EI	2.375	3.368	4.714	13.019	16.735	17.551	0.000	0.000	1.539	NQ	NQ	NQ	NQ	NQ	NQ	N/A	N/A	N/A	N/A	N/A	N/A
	Ten Storm Hardening Initiatives.	060198-EI																					
(b)	1 A Three-Year Vegetation Management Cycle for Distribution Circuits		4.832	5.345	9.219	9.577	9.600	9.900	0.000	0.000	10.560	NQ	NQ	NQ	NQ	NQ	NQ	N/A	N/A	N/A	N/A	N/A	N/A
(c)	2 An Audit of Joint-Use Attachment Agreements		0.000	0.000	0.000	0.260	0.260	0.260	0.000	0.000	0.594	NQ	NQ	NQ	0.000	0.059	0.119	N/A	N/A	N/A	N/A	N/A	N/A
(d)	3 A Six-Year Transmission Structure Inspection Program		0.415	0.456	0.567	0.765	1.224	1.266	0.000	0.000	0.519	NQ	NQ	NQ	0.000	0.000	0.017	N/A	N/A	N/A	N/A	N/A	N/A
(e)	4 Hardening of Existing Transmission Structures		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	N/A	N/A	N/A	N/A	N/A	N/A
(f)	5 Transmission and Distribution GIS		0.000	0.655	1.878	2.044	4.644	0.000	0.000	0.000	NQ	0.000	0.000	0.000	0.000	0.000	NQ	N/A	N/A	N/A	N/A	N/A	N/A
(g)	6 Post-Storm Data Collection and Forensic Analysis		0.000	0.000	0.000	0.040	0.000	0.070	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	N/A	N/A	N/A	N/A	N/A	N/A
(h)	7 Collection of Detailed Outage Data Differentiating Between the Reliability Performance of Overhead and Underground Systems		0.000	0.000	0.000	0.000	0.000	0.800	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	N/A	N/A	N/A	N/A	N/A	N/A
(i)	8 Increased Utility Coordination with Local Governments		0.000	0.007	0.014	0.021	0.028	0.030	NQ	NQ	NQ	0.000	0.000	0.000	NQ	NQ	NQ	N/A	N/A	N/A	N/A	N/A	N/A
(j)	9 Collaborative Research on Effects of Hurricane Winds and Storm Surge		0.000	0.000	0.005	0.020	0.010	0.010	0.000	0.000	0.000	0.000	0.000	0.000	NQ	NQ	NQ	N/A	N/A	N/A	N/A	N/A	N/A
(k)	10 A Natural Disaster Preparedness and Recovery Program		0.000	0.489	0.496	0.476	0.490	0.505	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	N/A	N/A	N/A	N/A	N/A	N/A
	Compliance with National Electric Safety Code's adoption of Extreme Wind Loading Standards.	070297-EI																					
(l)	1 New Distribution Facilities		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(m)	2 Major planned expansion, rebuild, or relocation of distribution facilities		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(n)	3 Critical infrasturture and major thoroughfares		0.000	0.000	0.000	1.002	0.990	1.058	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Mitigating flood and storm surge damage to underground and supporting overhead facilities.	070297-EI																					
(o)	1 Transmission		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(p)	2 Distribution		0.000	0.000	0.000	0.166	0.170	0.174	0.000	0.000	0.675	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(q)	**Placement of new and replacement distribution facilities to facilitate safe and efficient access for installation and maintenance.**	070297-EI	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	TOTALS		$7.622	$10.320	$16.893	$27.390	$34.151	$31.624	$0.000	$0.000	$13.887				$0.000	$0.059	$0.136						

Notes: All dollars in millions

NQ: Not Quantified - While there are some benefits, Tampa Electric has not been able to quantify these benefits at this time.

NA: Not Available - The information needed to quantify these benefits have not been made available to Tampa Electric at this time.

19. Please complete the table below:

	Any change from current plan.	Actual Cost									Estimated Cost								
		2013			2014			2015			2016			2015			2016		
		O&	Capit	Tot	O&	Capit	Tot	O&	Capit	Tot	O&	Capit	Tot	O&	Capit	Tot	O&	Capit	Tot
8-YearWooden Pole Inspection																			
10Storm Hardenin2lnitiatives																			
I A Three-Year																			
2 An Audit of Joint-Use																			
3 A Six-Year Transmission																			
4 Hardening of Existing Transmission Structures																			
5 Transmissi on and																			
6 Post-Storm Data																			
7 Collection of Detailed Outage data Differentiati																			
8 Increased Utility																			
9 Collaborative Research on Effects of																			
10 A Natural Disaster																			
Totals																			
Any Other Key Elements or																			

A. The table on the following page shows the actual and estimated costs for the 10-point storm hardening plan activities and the wood pole inspection program for Tampa Electric from 2013 through 2018:

Activity		Any change from current plan. (YIN) •	Actual Cost									Estimated Cost								
			2013			2014			2015			2016			2017			2018		
			O&M	Capital	Total	O&M	Capital	Total	O&M	Capital	Total	O&M	Capital	Total	O&M	Capital	Total	O&M	Capital	Total
8-YearWooden Pole Inspection PI"02f&m			$2.7	$40.2	$42.9	$3.1	$41.7	$44.8	$2.5	$35.9	$38.4	$1.2	$40.4	$41.5	$2.9	$32.5	$35.4	$2.9	$32.5	$35.4
10 Storm Hardenin2Initiatives																				
1	A Three-Year Vegetation Management Cycle for Distribution Circuits	Yes, now on 4 year plan	$9.2		$9.2	$9.6		$9.6	$11.7		$11.7	$9.4		$9.4	$9.6		$9.6	$9.9		$9.9
2	An Audit of Joint-Use Attachment Agreements	No	$0.3		$0.3	$0.7		$0.7			$0.0			$0.0			$0.0			$0.0
3	A Six-Year Transmission Sttucture Inspection program	Yes, now a 8-year cycle for above	$1.5		$1.5	$1.6		$1.6	$1.3		$1.3	$0.8		$0.8	$1.2		$9.6	$1.2		$0.0
4	Hardening of Existing Transmission Sttuctures	No		$1.0	$1.0		$0.7	$0.7		$0.6	$0.6		$0.8	$0.8		$0.8	$0.8		$0.8	$0.8
5	Transmission and Distribution GIS	No			$0.0			$0.0			$0.0			$0.0			$0.0			$0.0
6	Post-Stonn Data Collection and Forensic Analysis	No			$0.0			$0.0			$0.0			$0.0			$0.0			$0.0
7	Collection of Detailed Outage data Differentiating Between the Reliability Perfonnance of Overhead and Underground Systems	No			$0.0			$0.0			$0.0			$0.0			$0.0			$0.0
8	Increased Utility Coordination with Local Governments	No			$0.0			$0.0			$0.0			$0.0			$0.0			$0.0
9	Collaborative Research on Effects of Hurricane Winds and StonnSume	No			$0.0			$9.6			$11.7			$0.0			$0.0			$0.0
10	A Natural Disaster Preparedness and Recovery Program	No	$0.1		$0.1	$0.2		$0.2	$0.2		$0.2	$0.2		$0.2	$0.2		$0.2	$0.2		$0.2
		Totals	$13.7	$41.2	$54.9	$15.1	$42.3	$67.1	$15.7	$36.5	$63.9	$11.6	$41.1	$52.7	$13.9	$33.3	$55.6	$14.2	$33.3	$46.3
Any Other Key Elements or Proposed Initiatives																				